NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1923-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO RESET THE GENERAL RATE SCHEDULE ADJUSTMENTS, TO PLACE INTO EFFECT REVISED BASE RATES, AND TO IMPLEMENT OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE JUNE 15, 2023	**PROCEEDING NO. 23AL-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF DEREK S. KLINGEMAN

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

Confidential: Attachment DSK-5C

May 15, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1923-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO RESET THE GENERAL RATE SCHEDULE ADJUSTMENTS, TO PLACE INTO EFFECT REVISED BASE RATES, AND TO IMPLEMENT OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE JUNE 15, 2023	**) PROCEEDING NO. 23AL-XXXXE**

TABLE OF CONTENTS

SECTION **PAGE**

LIST OF ATTACHMENTS

Attachment DSK-1	CCOSS Model
Attachment DSK-2	Adjusted Functionalized Test Year Revenue Requirements
Attachment DSK-3	Excerpts of NARUC Cost Allocation Manual
Attachment DSK-4	Excerpts of RAP Cost Allocation Manual
Attachment DSK-5C	Confidential Probability of Dispatch – Peak Hours Analysis
Attachment DSK-5	Probability of Dispatch – Peak Hours Analysis (Public Version)

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

IN THE MATTER OF ADVICE NO. 1923-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO RESET THE GENERAL RATE SCHEDULE ADJUSTMENTS, TO PLACE INTO EFFECT REVISED BASE RATES, AND TO IMPLEMENT OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE JUNE 15, 2023	**)**	**PROCEEDING NO. 23AL-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF DEREK S. KLINGEMAN

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Derek S. Klingeman. My business address is 1800 Larimer Street, Suite 1100, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Public Service Company of Colorado ("Public Service" or the "Company"). My position is Principal Pricing Analyst in the Pricing and Planning Department.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As a Principal Pricing Analyst, I am responsible for development of new rate design proposals or modifications to existing rates to ensure effective price structures, increased options for customers, and compliance with regulatory requirements. A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications, provided at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present and sponsor the Company's electric Class Cost of Service Study ("CCOSS").

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following attachments:

- Attachment DSK-1 – CCOSS Model;
- Attachment DSK-2 – Adjusted Functionalized Test Year Revenue Requirements;
- Attachment DSK-3 – Excerpts of NARUC Cost Allocation Manual;
- Attachment DSK-4 – Excerpts of RAP Cost Allocation Manual;
- Attachment DSK-5C – Confidential Probability of Dispatch – Peak Hours Analysis; and
- Attachment DSK-5 – Public Version Probability of Dispatch – Peak Hours Analysis.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend the Commission approve the Company's proposed CCOSS, including the use of the new Probability of Dispatch – Peak Hours ("POD-PH") allocation methodology, and the resulting class cost responsibility.

II. CCOSS OVERVIEW AND RESULTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I provide a high-level overview of the CCOSS, including a discussion of its purpose, and provide the results of the CCOSS.

Q. WHAT IS THE PURPOSE OF THE CCOSS?

A. The purpose of the CCOSS is to allocate the total Test Year revenue requirement among the Company's major customer classes.[1] The CCOSS sets forth the revenue requirements by major customer class, which are used to establish the Company's proposed class revenue distribution and proposed base rates. Ultimately, the CCOSS measures the contribution each class makes to the Company's overall cost of service.

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. Table DSK-D-1 below summarizes the distribution of the Test Year revenue requirement by major customer class based on the proposed General Rate Schedule Adjustment ("GRSA") and GRSA-Energy factors from the Company's Direct Testimony in the pending Phase I Electric Rate Case, Proceeding 22AL-0530E (the "2022 Phase I"), which reflects existing base rate class cost allocation established in Proceeding No. 20AL-0432E (the "2020 Phase II") based on billing

[1] As discussed by Company witness Mr. Jeffrey R. Knighten, the Company presently is seeking Commission authorization in Proceeding No. 22AL-0530E to establish an overall base rate revenue requirement for Public Service's retail electric operations based upon a test year ending December 31, 2023 (the "Test Year"). The CCOSS allocates the Test Year revenue requirement to the various customer classes as part of the process of designing base rates, so that when those rates are applied to Test Year billing determinants, it yields the Test Year revenue requirement.

determinants for a test year ended August 31, 2019 (the "August 2019 Test Year"). Table DSK-D-1 also shows the distribution of the Test Year revenue requirement by customer class based on the recommended CCOSS results. The CCOSS results shown are based on the use of the new POD-PH cost allocation methodology for production, transmission, and distribution substation costs, which, as discussed in more detail below, account for approximately 59 percent of the total Test Year revenue requirement. The POD-PH cost allocation methodology is described in more detail later in my Direct Testimony.

TABLE DSK-D-1
Summary of CCOSS Results

	Current Base Rate Revenue Requirement*	Proposed Base Rate Revenue Requirement	Difference	%
Residential	$1,084,746,840	$1,098,688,161	$13,941,321	1.3%
Small Commercial	$131,789,619	$122,878,532	($8,911,087)	-6.8%
Secondary General	$900,839,338	$905,171,575	$4,332,237	0.5%
Primary General	$208,424,113	$201,058,345	($7,365,767)	-3.5%
Transmission General	$89,866,271	$91,108,993	$1,242,722	1.4%
Street Lighting	$47,070,502	$43,831,160	($3,239,342)	-6.9%
Traffic Lighting	$1,460,003	$1,459,919	($84)	0.0%
Total	$2,464,196,686	$2,464,196,686		

* Reflects 2022 Phase I Proposed GRSA and GRSA-E
Note: Total Revenue Requirement Excludes Interconnection Revenues

Q. HOW IS THE DISTRIBUTION OF THE TEST YEAR REVENUE REQUIREMENT BY CUSTOMER CLASS UTILIZED IN THIS PROCEEDING?

A. Each class's share of the total revenue requirement forms the revenue targets that the Company's proposed base rates are designed to recover. When those base rates are applied to Test Year billing determinants, it will yield the Test Year revenue requirement by class (and overall). Mr. Jeffrey R. Knighten sponsors the Company's proposed rates in this proceeding and discusses the rate design process in more detail in his Direct Testimony.

III. COST ALLOCATION PROCESS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I describe the cost allocation process and explain how that process is implemented through the CCOSS. I begin by identifying the major customer classes used in the CCOSS and the individual electric service schedules that comprise each major customer class. I then discuss the steps in the cost allocation process: functionalization, classification, and allocation. I end this section by discussing the use of load research data in the CCOSS and the CCOSS model itself.

Q. WHAT PRINCIPLES GUIDE THE COMPANY'S COST ALLOCATION PROPOSAL?

A. In this proceeding, the Company is focused on the principles of fairness and stability. While other factors also influence our approach to cost allocation, these two receive the greatest consideration.

Q. WHAT DO YOU MEAN BY "FAIRNESS" IN THE CONTEXT OF COST ALLOCATION?

A. In this context, fairness refers to customers that use system resources helping to pay for system resources. This was one of the short comings of the allocation methodology previously used by the Company to allocate production, transmission, and distribution substation costs to customer classes:[2] it over-

[2] As discussed in more detail below, that prior methodology was the "4CP-AED" allocation factor. 4CP-AED stands for 4 Coincident Peak ("CP") – Average and Excess Demand ("AED").

emphasized usage during the four coincident peak hours at the expense of usage during other times of the year. The Company recommends that class cost allocation should consider many more hours than just the four coincident peaks so that customer groups that are using production, transmission and distribution substation resources are paying their fair share of those costs.

Fairness also considers that different types of resources should be allocated differently based on when those resources are used. By way of an extreme, hypothetical example: if a particular customer class only used electricity at night, it would be unfair to allocate costs associated with solar generation (which occurs exclusively during the day) to those customers.[3]

Q. WHAT DO YOU MEAN BY "STABILITY" IN THE CONTEXT OF COST ALLOCATION?

A. I am referring to whether the particular cost allocation methodology results in relatively large changes in cost responsibility as a result of relatively minor changes in underlying data. We have recently observed that the 4CP-AED methodology is not particularly stable due to it being sensitive to usage patterns in only four hours of a year. An allocation methodology based on a broader swath of hours will be more stable than one based on only four hours of the year. As discussed later in my testimony, the Company is proposing to use the POD-PH methodology for

[3] This is a hypothetical example only. The Street Lighting class does have some usage during the daylight hours due to lighting used in tunnels and other 24-hour lighting applications. Further, the Company currently does not have solar generation costs in its base rate revenue requirement.

production, transmission, and distribution substations in this proceeding as a means of addressing the instability of the 4CP-AED methodology.

Q. DOES THE COMPANY ALSO CONSIDER COST CAUSATION IN ITS COST ALLOCATION RECOMMENDATIONS?

A. Yes. Cost causation also is a foundational principle associated with cost allocation. Any allocation methodology should be based on customer usage patterns, with an emphasis on the loads and behaviors that drive costs on a utility system. However, when performing an embedded cost allocation analysis, all of the costs are fixed in nature and there really is not a forward-looking cost causation. To put it another way, a vast majority of the costs in the Company's Test Year are based on investments that we made many years ago and customer load patterns in 2023 did not and do not influence those investments. As such, cost causation is a relevant cost allocation principle, but not necessarily determinative.

Q. PLEASE PROVIDE A SUMMARY OF HOW THE COMPANY FUNCTIONALIZED, CLASSIFIED, AND ALLOCATED COSTS IN THIS CASE.

A. Table DSK-D-2 below summarizes the functionalization, classification, and allocation of the Test Year revenue requirement.

TABLE DSK-D-2
Summary of Cost Allocation Process

Step One Functionalization	Revenue Requirements	Step Two Classification	Step Three Allocation
PRODUCTION			
Steam Production	$359,457,072	Capacity Related	POD-PH
Hydro Production	$45,294,229	Capacity Related	POD-PH
Comb Turbine Production	$340,119,393	Capacity Related	POD-PH
Purchased Capacity	-$25,749	Capacity Related	POD-PH
Transmission Interconnect	$5,942,159	Capacity Related	POD-PH
Production Energy (Company-Owned Wind)	$289,391,754	Energy Related	POD-PH
TRANSMISSION			
Transmission System	$304,420,450	Capacity Related	POD-PH
Transmission by Others	$10,486,074	Capacity Related	POD-PH
DISTRIBUTION			
Distribution Substations	$99,354,662	Capacity Related	POD-PH & Direct Assignment
Primary Distribution System	$547,434,187	Capacity Related	Class NCP
Secondary Distribution System	$147,117,134	Capacity Related	Class NCP & Sum of Max Demands
Service Lateral	$41,163,283	Customer Related	Sum of Max Demands
Metering	$79,500,480	Customer Related	Weighted Cost of Meters
Lighting	$36,758,828	Customer Related	Direct Assignment
CUSTOMER OPERATIONS			
Meter Reading	$24,197,012	Customer Related	Weighted Factors
Customer Accounting	$32,567,407	Customer Related	Weighted Factors & Direct Assignment

A. Major Customer Classes

Q. PLEASE IDENTIFY THE MAJOR CUSTOMER CLASSES USED IN THE COMPANY'S CCOSS.

A. The major customer classes used in the Company's CCOSS include:

- Residential;
- Small Commercial;
- Commercial and Industrial ("C&I") Secondary;
- C&I Primary;
- C&I Transmission;
- Street and Area Lighting; and
- Traffic Signal Lighting.

Q. PLEASE DESCRIBE HOW INDIVIDUAL ELECTRIC RATE SCHEDULES ARE AGGREGATED INTO THESE MAJOR CUSTOMER CLASSES FOR ALLOCATION PURPOSES.

A. A designated major customer class in the CCOSS may include multiple rate schedules. For example, the C&I Primary customer class includes Schedules PG, PG-CPP, SCS-7, and PST. Costs are not directly allocated to each of these rate schedules. Instead, costs are allocated to the C&I Primary customer class. In this example, the costs allocated to the C&I Primary class are then used to design rates for Schedules PG, PG-CPP, SCS-7, and PST. Table DSK-D-3 below outlines what rate schedules are included in each major customer class for purposes of the CCOSS.

TABLE DSK-D-3:
Mapping of Rate Schedules to Major Customer Classes

Rate Schedule	Customer Class	Rate Schedule	Customer Class
R	Residential	PG	Primary C&I
RD	Residential	PG-CPP	Primary C&I
RE-TOU	Residential	SCS-7	Primary C&I
R-OO	Residential	PST	Primary C&I
C	Small Commercial	TG	Transmission C&I
C-TOU	Small Commercial	TG-CPP	Transmission C&I
NMTR	Small Commercial	SCS-8	Transmission C&I
		TST	Transmission C&I
SGL	Secondary C&I		
SG	Secondary C&I	MSL	Lighting
S-EV	Secondary C&I	MI	Lighting
S-EV-CPP	Secondary C&I	ESL	Lighting
SG-CPP	Secondary C&I	SL	Lighting
SG-TOU	Secondary C&I	SSL	Lighting
SPVTOU A	Secondary C&I	COL	Lighting
SPVTOU B	Secondary C&I	SLU	Lighting
SST	Secondary C&I		
		TSL	Traffic Signal

Q. ARE THERE ANY CHANGES TO THE INDIVIDUAL RATE SCHEDULES THAT ARE AGGREGATED INTO THE MAJOR CUSTOMER CLASSES AS COMPARED TO THE COMPANY'S LAST PHASE II RATE PROCEEDING?

A. Yes. The Company has added several rate schedules to its electric tariff since the 2020 Phase II, including Schedules EDR, SG-TOU, C-TOU, and S-EV-CPP. Schedules SG-TOU and S-EV-CPP have been aggregated into the C&I Secondary customer class, and Schedule C-TOU has been aggregated to the Small Commercial customer class. Schedule EDR does not map to any particular rate class and customers on Schedule EDR are excluded from the CCOSS for cost allocation purposes.[4] Additionally, Schedule RD-TDR expired on January 1, 2022, and Schedules STOU and PTOU expired on January 1, 2023.

B. Functionalization

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION OF COSTS.

A. Functionalization entails the sorting of plant investment and expenses by system component, such as production, transmission, distribution, or customer operations. For the most part, the functionalization of costs is accomplished through the Company's accounting system. For example, Federal Energy Regulatory Commission ("FERC") Account 312 is Boiler Plant Equipment. Boiler Plant Equipment is equipment used in the production of steam, to be used primarily for generating electricity. Therefore, FERC Account 312 is assigned to steam production.

Q. PLEASE DESCRIBE HOW THE COMPANY FUNCTIONALIZED COSTS FOR ITS CCOSS PRESENTED IN THIS PROCEEDING.

A. The Company's costs were first separated into 17 specific cost functions. Each rate base or expense item was then assigned to one of the specific cost functions or spread across a number of functions.

Q. DID THIS FUNCTIONALIZATION OCCUR IN THE 2022 PHASE I?

A. Yes. Functionalization occurs in Phase I rate cases. For this proceeding, that means the Company is relying on the revenue requirements study sponsored by

[4] There were no Economic Development Rate ("EDR") customers in the Test Year.

Company witness Mr. Arthur P. Freitas in support of the Test Year in his Direct Testimony in the 2022 Phase I.[5]

Q. DID YOU MAKE ANY ADJUSTMENTS TO MR. FREITAS'S FUNCTIONALIZATION?

A. Yes. For this Phase II, the Company made one small change to the functionalized costs, moving approximately $5.5 million from Secondary Distribution to Primary Distribution. This amount represents the cost of capacitors in FERC Account 368. This was a modification that the Company adopted in the 2020 Phase II and has a very minor impact to overall class cost allocation. Attachment DSK-2 contains the adjusted functionalized Test Year revenue requirements, which is the input to the CCOSS.

C. <u>Classification</u>

Q. PLEASE DESCRIBE THE CLASSIFICATION OF COSTS.

A. Classification takes the functionalization step beyond the accounting records by identifying the primary driver of each cost. Here, this generally refers to the three basic types of costs: (1) energy-related costs incurred to generate the energy that customers require; (2) demand-related costs (sometimes referred to as capacity-related costs) incurred to ensure reliable service during periods when system load is at its highest; and (3) customer-related costs incurred to connect customers to the system, bill them, and administer their service on an ongoing basis. These

[5] *See* Proceeding No. 22AL-0530E, Hrg. Ex. 120, Attachment APF-1 (Freitas Direct).

three cost classifications generally correspond to the primary types of charges used to recover costs in base rates: volumetric or energy charges, which are based on kilowatt-hours (kWh); demand charges, which are based on kilowatts (kW) and applicable to some but not all rate schedules; and service and facilities ("S&F") charges, which typically are fixed monthly amounts.

Q. CAN YOU PROVIDE EXAMPLES OF COSTS THAT ARE CONSIDERED ENERGY-RELATED?

A. Yes. The most significant energy-related costs are the costs of fuel and purchased energy, though, for Public Service, these costs are recovered through the Electric Commodity Adjustment ("ECA") and not in base rates. The non-fuel, energy-related costs recovered in base rates include the costs of chemicals, water, and ash handling. These costs vary with the amount of electric energy produced. The Company also classifies the cost of Company-owned wind resources as energy-related.

Q. WHAT ARE DEMAND-RELATED COSTS?

A. Demand-related costs are those that vary in response to peak demand by customers. The peak demands can be system coincident peak demands or more localized non-coincident peak demands.

Q. CAN YOU PROVIDE EXAMPLES OF DEMAND-RELATED COSTS?

A. Yes. Investments in generation and transmission resources generally are considered demand related costs. Also, a majority of distribution infrastructure is considered to be demand-related.

Q. CAN YOU PROVIDE EXAMPLES OF COSTS THAT ARE CONSIDERED CUSTOMER-RELATED?

A. Yes. Generally, the investment costs of meters, as well as services and expenses associated with meter reading, billing, and customer accounting, are classified as customer-related costs, as these costs vary with the number of customers on the system.

Q. PLEASE IDENTIFY HOW THE COMPANY CLASSIFIED ITS FUNCTIONALIZED COSTS.

A. Table DSK-D-2 above shows the classification of the functionalized Test Year revenue requirement.

D. <u>Allocation and Direct Assignment</u>

Q. PLEASE DESCRIBE THE PROCESS OF ALLOCATING COSTS AMONG MAJOR CUSTOMER CLASSES.

A. Allocation generally refers to the process of assigning costs that have been functionalized and classified to various customer classes.

Q. ARE ALL COSTS ALLOCATED IN THE CCOSS?

A. No. When costs can be specifically attributed to a specific major customer class or an individual customer, then those costs are directly assigned to that customer class or customer. As discussed below, there are only two categories of costs in the Company's CCOSS that are directly assigned. The vast majority of costs cannot be specifically attributed to a specific major customer class or an individual customer and therefore are allocated to the major customer classes using different allocation factors.

Q. PLEASE DESCRIBE THE TWO CATEGORIES OF COSTS THAT WERE DIRECTLY ASSIGNED IN THE CCOSS.

A. The two categories of costs directly assigned in the CCOSS are: (1) distribution substations; and (2) lighting equipment. Certain distribution substations may be dedicated to serving single large customers in the C&I Transmission class. If such a customer wants the Company to own, operate, and maintain a substation on their behalf, the costs of the substation are directly assigned to that individual customer through their specific S&F charge. Separately, lighting equipment is directly assigned to the Lighting class because they are the only customers that cause the Company to incur lighting-related costs.

Q. HOW ARE COSTS ALLOCATED TO CUSTOMER CLASSES?

A. Costs are allocated using a variety of allocation factors. The allocation factors typically reflect some measure of class loads or class service characteristics. For example, meter reading costs generally are allocated to various customer classes based on the weighted average cost of meters installed.

Q. ARE THERE MAJOR CUSTOMER CLASSES THAT DO NOT HAVE CERTAIN COSTS ALLOCATED TO THEM?

A. Yes. The C&I Primary and the C&I Transmission customer classes do not use the secondary distribution system since they are connected to the Company's system at the primary and transmission voltage levels, respectively. Therefore, these major customer classes are not allocated any costs associated with the secondary distribution system. Further, because the C&I Transmission customer class is connected to the Company's system at transmission voltage, that customer class does not use the primary distribution system and is not allocated primary distribution costs. Finally, consistent with the Company's rebuttal testimony in the 2020 Phase II, Residential and Small Commercial customers are not allocated costs associated with managing key accounts.

Q. DOES THE CCOSS INCLUDE ALLOCATION METHODOLOGIES EMPLOYED IN PRIOR PHASE II RATE CASES?

A. Yes. The CCOSS allocates primary distribution, secondary distribution, meters, metering reading, and customer accounting costs using the same allocation methodologies employed in prior Phase II rate cases. As discussed in more detail below, the Company is recommending new allocation methodologies for fixed production costs (production capacity), variable production costs (production energy), transmission costs, distribution substation costs, and service lateral costs.

1. <u>Primary Distribution</u>

Q. PLEASE DESCRIBE THE ALLOCATION OF PRIMARY DISTRIBUTION COSTS.

A. Primary distribution costs are allocated in the CCOSS based on the class annual non-coincident peak ("NCP") allocation factor, which reflects each major customer class's peak demand regardless of when that peak occurs. The class annual NCP allocation factor compares each class's NCP to the sum of class NCP's.

Q. WHY DOES THE COMPANY ALLOCATE PRIMARY DISTRIBUTION COSTS USING THE NCP ALLOCATION FACTOR?

A. The primary distribution system is made up of 13 Kilovolt ("kV") and 25 kV distribution feeders between the distribution substations and the distribution transformers. Each feeder must be sized to meet the coincident peak demand of the group of customers that it serves. The level of diversity on these feeders falls somewhere between the fully diverse load that exists at the generation level and the sum of the individual maximum demands of all the customers served from the feeder. The Company recognizes this diversity by using the class peak demand during the Test Year, regardless of when this class peak demand occurs, to allocate primary distribution system capacity costs.

Q. WHY IS IT IMPORTANT TO RECOGNIZE LOAD DIVERSITY WHEN CREATING ALLOCATION FACTORS?

A. It is important to recognize the role of load diversity in the choice of allocation factors for the various components of the electric system. At all levels of the system, adequate capacity must be installed to meet the expected maximum load at that point on the system. At the delivery point to an individual customer, there is no diversity because the delivery system must be sized to meet the customer's maximum load, regardless of the timing or duration of that maximum load. However, as you move up to higher levels, through the secondary transformers and primary distribution feeders to the distribution substations, the maximum load at any particular point on the system will be less than the sum of the maximum demands of all customers on that portion of the system because of the diversity among those loads. The highest level of diversity is reached at the generation level, where the loads of all customers on the system are aggregated. Accordingly, at lower levels of the distribution system, it is necessary to use an allocation method that takes into account the decreasing level of load diversity.

The primary distribution system is an “in-between” portion of the system – it has more diversity than the delivery point to an individual customer, but less diversity than points further upstream. The class annual NCP allocation factor appropriately accounts for the load diversity in the primary distribution system. Further, this allocation factor has been used in CCOSSs approved by the Commission in prior Phase II rate cases.

2. Secondary Distribution

Q. PLEASE DESCRIBE THE ALLOCATION OF SECONDARY DISTRIBUTION COSTS.

A. Secondary distribution costs are allocated using the secondary NCP allocation factor. The secondary NCP allocation factor is the average of the class NCP and the sum of individual customers’ maximum demands.

Q. WHY DOES THE COMPANY ALLOCATE SECONDARY DISTRIBUTION COSTS USING THE SECONDARY NCP ALLOCATION FACTOR?

A. The secondary distribution system includes distribution transformers serving either individual customers or small groups of customers, secondary voltage conductors and other low-voltage equipment. The load diversity is much lower at this level of the system. However, only using the sum of the individual customer maximum demands to allocate secondary distribution costs would not recognize that there is some load diversity on the secondary system, while using only the class NCP to allocate secondary costs would overstate the diversity. To balance these considerations, the Company allocated the capacity costs of the secondary distribution system to customer classes taking service at secondary voltage using the secondary NCP allocation factor consistent with CCOSSs from prior Phase II proceedings.

3. Meters, Meter Reading, and Customer Accounting

Q. PLEASE DESCRIBE THE ALLOCATION OF METER, METER READING, AND CUSTOMER ACCOUNTING COSTS.

A. Meter, metering reading, and customer accounting costs are allocated based on the number of customers in each customer class with a weighting factor that reflects each class's particular costs. For customer accounting costs, which comprises costs recorded to FERC account 903 (i.e. customer records and collection expenses), the Company made an adjustment for the portion of these costs attributed to managing key accounts. These specific costs are related to serving the C&I classes, not Residential or Small Commercial, so the adjustment removes the portion of these costs that is allocated to Residential and Small Commercial and re-allocates these costs between the C&I classes based on customer count and energy weighting.

4. Production, Transmission and Distribution Substations

Q. HOW ARE PRODUCTION, TRANSMISSION, AND DISTRIBUTION SUBSTATION COSTS ALLOCATED IN THE CCOSS?

A. Production, transmission, and distribution substation costs are all allocated using the POD-PH methodology.

Q. HAS THE COMPANY USED THE POD-PH METHODOLOGY IN PRIOR PHASE II RATE CASES?

A. No. As discussed by Company witness Mr. Steven W. Wishart in his testimony, the Company developed the POD-PH methodology in response to the Commission's direction that the Company pursue an allocation methodology that can apply to all of the Company's production plant costs, regardless of the fuel source for the underlying generating facilities.[6] Prompted by Decision No. C21-0536 and guided by the principles of fairness and stability, the Company is proposing to allocate production, transmission, and distribution substation costs based on the POD-PH methodology.

[6] Proceeding No. 20AL-0432E, Decision No. C21-0536, at p. 20, ¶47 ("We also find that Staff's request is reasonable and appropriate. While the Rush Creek Wind Farm provides primarily energy benefits to the grid, it represents the beginning of likely future generation asset investment. We agree that Public Service should develop mechanisms to allocate generation assets on a consistent basis. As a result, we direct the Company to file, as part of its next Phase II rate case, an alternative CCOSS methodology with the goal of applying more consistent allocation treatment across all electric generation and storage assets").

Q. WHY DOES THE COMPANY USE THE SAME ALLOCATION METHODOLOGY FOR PRODUCTION, TRANSMISSION, AND DISTRIBUTION SUBSTATION COSTS?

A. Transmission and distribution substations assets exist to deliver energy produced by generation assets to customers, so it makes sense to use the same methodology for all three types of costs (production, transmission, and distribution substations).

Q. HAS THE COMPANY USED THE SAME COST ALLOCATION FACTOR FOR ALL THREE TYPES OF COSTS (PRODUCTION, TRANSMISSION, AND DISTRIBUTION SUBSTATIONS) IN PRIOR CASES?

A. Yes. It is the Company's longstanding practice to allocate production, transmission, and distribution substations in the same way.

Q. PLEASE PROVIDE A HIGH-LEVEL DESCRIPTION OF THE POD-PH METHODOLOGY.

A. At a high level, the POD-PH methodology allocates the cost of different types of generation resources based on when those resources are expected to be producing power, but limits that analysis to the 1,000 peak load hours in recognition that it is generally the highest load hours that drive investments in generation. It simultaneously allocates demand-related costs and energy-related costs.

Q. WHAT IS THE BASIS OF THE POD-PH METHODOLOGY?

A. The POD-PH methodology draws upon the probability of dispatch ("POD") allocation methodology, which is identified as a production plant cost allocation methodology in the 1992 National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual,[7] and is referred to as a "Modern" approach to allocating production costs in the Regulatory Assistance Project ("RAP") Cost Allocation Manual.[8] The POD methodology assigns the cost of generation assets to the hours in which they are expected to be running and then allocates costs to customer classes based on each classes' share of load in each hour.

Q. HOW DOES THE POD-PH ALLOCATOR DIFFER FROM THE POD ALLOCATION METHODOLOGY DISCUSSED IN THE NARUC AND RAP COST ALLOCATION MANUALS?

A. The POD methodology described in the NARUC and RAP Cost Allocation Manuals both consider customer usage in all hours of the year. The POD-PH allocator modifies the standard POD methodology by limiting the analysis to the top 1,000 peak load hours in the year.

---

[7] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual at p. 62 (1992) (the "NARUC Electric Cost Allocation Manual"). The portions of the NARUC Electric Cost Allocation Manual discussing the probability of dispatch allocation methodology are included as Attachment DSK-3 to my Direct Testimony. The full NARUC Electric Cost Allocation Manual is publicly available at https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD.

[8] Jim Lazar, Paul Chernick, and William Marcus, Electric Cost Allocation for a New Era: A Manual at p. 133 (2020) ("RAP Cost Allocation Manual"). The portions of the RAP Cost Allocation Manual discussing the probability of dispatch allocation methodology are included as Attachment DSK-4 to my Direct Testimony. The full RAP Cost Allocation Manual is publicly available at https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

Q. WHY IS THE COMPANY MODIFYING THE PROBABILITY OF DISPATCH METHODOLOGY TO FOCUS SPECIFICALLY ON PEAK HOURS?

A. There are three reasons. First, while the RAP Cost Allocation Manual recognized POD as a modern methodology for allocating generation costs, the RAP Cost Allocation Manual also recognized some limitations to the approach, namely that it captures how resources currently are used but does not necessarily capture why those investments were made in the first place. By limiting the POD-PH allocator to the top 1,000 hours, the cost allocation is focused on the most critical hours of the year and better reflects the fact that generation historically was added to address peak capacity needs. Even with an increased reliance on wind and solar resources, hours with the highest customer loads still play an important role in assessing investments in new generation resources.

Second, utilizing all hours would result in significant costs being allocated during low load hours when renewable generation likely would be curtailed. We do not think it is appropriate to allocate costs based on off-peak load, which may actually help integrate higher levels of renewables.

Third, the Company added the 1,000 hours refinement to minimize the cost shifts resulting from the movement to a new allocation methodology. In previous Phase II proceedings, production costs were allocated based on the 4CP-AED allocator, which is strongly influenced by relative class usage during the four summer coincident peaks. Conversely, the POD methodology is more similar to an energy-based allocation. Moving from an allocator that is strongly influenced by coincident peaks to a more energy-based allocation (like POD) generally will shift costs from low load factor groups (Residential) to higher load factor groups (C&I Primary and C&I Transmission). Restricting the allocation methodology to a smaller number of hours (1,000 verses 8,760) moderates the difference between coincident peak and energy-based methodologies, helps keep class cost allocation stable between cases, and dampens changes in cost responsibility between specific customer classes.

Q. HOW DID THE COMPANY SETTLE ON USING 1,000 HOURS IN THE POD-PH ALLOCATOR?

A. The Company selected the top 1,000 on-peak hours because it is approximately equal to the number of on-peak hours, as defined in Schedules RE-TOU and C-TOU.

Q. ARE THE 1,000 HOURS USED IN THE POD-PH ALLOCATOR THE TOP 1,000 LOAD NET OF RENEWABLE HOURS?

A. No. The Company did not select the top 1,000 load net of renewable hours because the Commission directed that the Company develop an allocation methodology that applies consistently to all generation assets[9] and it would not make sense to allocate the cost of renewable resources based on load net of renewables. The Company currently recovers the cost of Company-owned wind resources in base rates and is likely to recover the cost of some solar resources

[9] Proceeding No. 20AL-0432E, Decision No. C21-0536, at p. 20, ¶47 (" . . . we direct the Company to file, as part of its next Phase II rate case, an alternative CCOSS methodology with the goal of applying more consistent allocation treatment across all electric generation and storage assets").

through base rates in the future. Using the top 1,000 load hours allows for a consistent cost allocation methodology that applies to the Company's current and future generation fleet.

Q. PLEASE DESCRIBE THE FIRST STEP IN THE DEVELOPMENT AND CALCULATION OF THE POD-PH ALLOCATOR.

A. The first step of the process is to develop a revenue requirement for each production plant category. For our analysis, we calculated the revenue requirements for each plant included in rate base. The revenue requirements included the carrying costs, taxes, and depreciation associated with plant investments, as well as operation and maintenance expenses. Then each plant was placed in one of the following categories: hydro, baseload, intermediate, peaking, solar, wind, or storage.[10] The following Table DSK-D-4 summarizes the production revenue requirements by category.

TABLE DSK-D-4
Production Cost for Probability of Dispatch

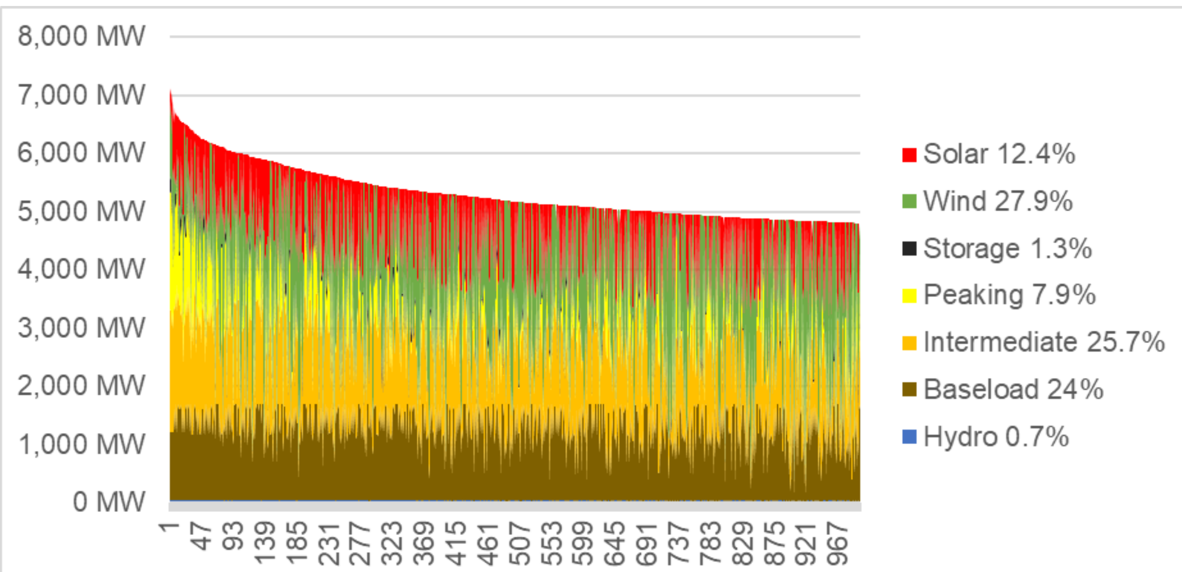
Generation Category	Total Cost
Hydro	$21,974,293
Baseload	$381,000,822
Intermediate	$235,291,594
Peaking	$125,385,434
Solar	$0
Wind	$243,837,751
Storage	$32,232,500
Total	$1,039,722,393

[10] The Federal Energy Regulatory Commission Uniform System of Accounts does not use the same categorization, so the Company had to manually assign costs to the appropriate category for the POD-PH analysis.

Q. PLEASE DESCRIBE THE NEXT STEP IN THE DEVELOPMENT AND CALCULATION OF THE POD-PH ALLOCATOR.

A. Next, the Company estimated relative output of each generation type during the top 1,000 hours. Specifically, the Company utilized the PLEXOS simulation model that it also uses for forecasting the costs in the ECA rider to estimate the energy output of each type of generation in the top 1,000 hours of 2023.[11] The following figure illustrates the simulated dispatch in the top 1,000 hours.

Figure DSK-D-1
Top 1,000 Hours Dispatch Simulation

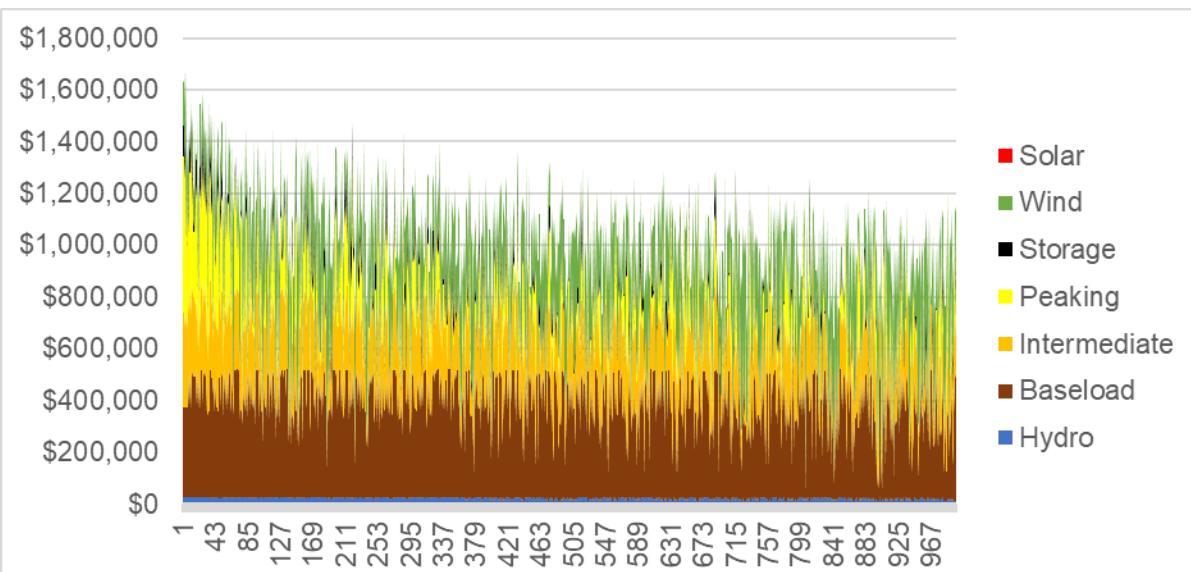


[11] The simulation excluded market sales and purchases in order to simulate only those resources that the Company controls.

Q. PLEASE DESCRIBE THE NEXT STEP IN THE DEVELOPMENT AND CALCULATION OF THE POD-PH ALLOCATOR.

A. The third step is to calculate the cost of generation in each hour based on the estimated dispatch and the cost of each production type. This is done by dividing the total cost of each production type by the estimated generation by type in the top 1,000 hours. This average cost is then applied to generation in each hour to derive the hourly production cost to be allocated. The following figure illustrates the calculated hourly system costs. Note that the figure excludes costs of generation procured through power purchase agreements, which is why it excludes costs associated with solar.

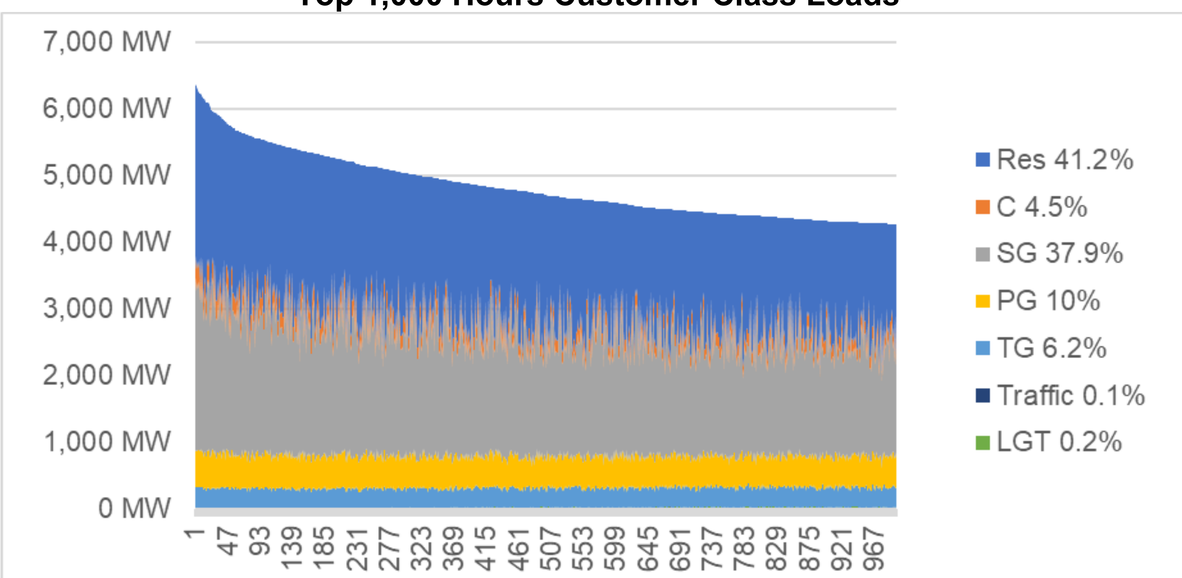
Figure DSK-D-2
Top 1,000 Hours Base Rate Production Costs



Q. WHAT IS THE FINAL STEP IN THE DEVELOPMENT AND CALCULATION OF THE POD-PH ALLOCATOR?

A. The final step is to calculate each customer class's share of load in each hour and allocate the hourly production costs based on that share of load. The following figure illustrates customer class loads in each of the 1,000 top load hours. The complete POD-PH analysis is provided as Attachment DSK-5C to my testimony.

Figure DSK-D-3
Top 1,000 Hours Customer Class Loads



5. <u>Service Laterals</u>

Q. PLEASE DESCRIBE THE ALLOCATION OF SERVICE LATERAL COSTS.

A. The Company proposes to allocate customer service lines based on the sum of individual maximum demands, which is also used, in part,[12] to allocate the secondary distribution system.

[12] The allocator used for the secondary distribution system is a hybrid allocation which uses both the sum of individual max demands and the class NCP in order to allocate costs.

Q. IS THIS A CHANGE FROM HOW SERVICE LATERALS WERE ALLOCATED IN THE COMPANY'S LAST PHASE II RATE CASE?

A. Yes. We are recommending this change because the new approach incorporates more accurate data for estimating customer weightings. Further, the RAP Cost Allocation Manual cites this methodology as an often-used approach for allocating service lateral costs.[13]

E. Load Research Data

Q. DO SOME OF THE ALLOCATORS DISCUSSED ABOVE UTILIZE LOAD RESEARCH DATA?

A. Yes. The Company is in the process of deploying Advanced Meters to all of its electric customers.[14] Once that deployment is complete, we will be able to collect interval data on all customers thereby capturing each customer's (and class's) share of total retail usage, which is needed to calculate class annual NCPs and the sum of individual maximum demands. For this case (and in prior Phase II rate cases), however, we have relied on load research data in the calculation of those allocation factors (and for calculation of coincident peaks).

---

[13] RAP Cost Allocation Manual, Section 11.4 Allocation Factors for Service Drops.

[14] An "Advanced Meter" as the term is used in my Direct Testimony includes Advanced Metering Infrastructure ("AMI") and interval data meters. A customer opting out of AMI would receive an interval data meter.

Q. DO YOU PERSONALLY DEVELOP THE LOAD RESEARCH DATA USED IN THE CALCULATION OF CCOSS ALLOCATION FACTORS?

A. No. This information is provided to me by the Company's Quantitative Risk Analysis Department.

Q. WHAT IS LOAD RESEARCH?

A. Load research is the systematic collection and analysis of customers' electrical energy and demand requirements by time-of-day, month, season, and year. This data, which includes load research samples, is collected and analyzed by major customer class, strata of major customer classes, and other subsets of major customer classes. Load research helps the Company better understand customers' consumption patterns, their consumption responses to various factors, and the impact of customers' energy requirements on the electric utility's system. And, as in this case, load research data can be used in the development of CCOSS allocators and in rate design.

Q. CAN YOU BRIEFLY DESCRIBE PUBLIC SERVICE'S LOAD RESEARCH PROGRAM?

A. Yes. As discussed above, the Company currently does not have interval data metering (interval demand recorders or "IDRs") in place for every customer in all major customer classes to collect the data that would directly capture each customer's (and class's) share of total retail usage. The Company therefore uses a combination of load data from census classes (the classes with IDRs) and sample classes (the classes without IDRs). For those classes without IDRs, the

Company creates a sample of customers within the class and installs meters capable of collecting the necessary load data. Those meters record the use of each sampled customer for every 15-minute interval of the year. The recorded data is then extrapolated to create demand data for the entire class.

Q. HOW ARE THE LOAD RESEARCH SAMPLES CREATED?

A. The load research samples are developed using a stratified random sampling method. This technique divides the class of interest into smaller groups with like-characteristics. This method effectively reduces the overall variance of the class, thereby reducing the sample size. The samples are designed to meet or exceed the "90/10" load research standard specified by the Federal Energy Regulatory Commission's regulations implementing the Public Utilities Regulatory Policies Act of 1978.[15]

Q. DID THE COMPANY DEVELOP LOAD RESEARCH SAMPLES FOR EACH MAJOR CUSTOMER CLASS?

A. No. The Company utilized load research samples for the Residential, Small Commercial, and C&I Secondary major customer classes. These classes are the "non-census" classes. Customers in other major customer classes have IDRs (making them the census classes), so information for those classes can be gathered directly.

[15] 44 Fed. Reg. 33,874 (June 13, 1979).

Q. WHAT INFORMATION DID THE QUANTITATIVE RISK ANALYSIS DEPARTMENT PROVIDE FOR USE IN THE CCOSS?

A. The Quantitative Risk Analysis Department provided the following information for the Test Year: (1) monthly class CP and monthly class NCP for the census classes (C&I Primary and C&I Transmission) and the non-census classes (Residential, Small Commercial, and C&I Secondary); and (2) annual non-coincident peak demand ("NCD") for the Residential, Small Commercial, C&I Secondary, and combined Primary General and special contract classes.

Q. PLEASE DEFINE THE TERMS "MONTHLY CLASS COINCIDENT PEAK," "MONTHLY CLASS NON-COINCIDENT PEAK," AND "ANNUAL NON-COINCIDENT PEAK DEMAND."

A. The *monthly retail system peak* is the 60-minute interval in each month in which Public Service's retail load experiences the highest demand, and each retail class's demand during that 60-minute interval is the *monthly class coincident peak*. The *monthly class peak* is the 15-minute interval in each month in which a class experiences its highest demand. Unless the monthly class peak occurs during the same time period as the monthly retail system peak, the monthly class peak is a *monthly class non-coincident peak*. The *annual non-coincident peak demand* is the sum of the individual customers' maximum demands regardless of time of occurrence. This metric represents a theoretical maximum demand if all customers experienced their maximum demand simultaneously.

Q. HAS THE COMPANY CHANGED HOW IT DEVELOPS THE DEMAND INPUTS FOR THE CCOSS?

A. No. The information provided by Quantitative Risk Analysis Department was developed using the same methodologies that were used to support the Company's 2016 Phase II rate case (Proceeding No. 16AL-0048E) and 2020 Phase II rate case.

Q. IS THE INFORMATION PROVIDED BY THE QUANTITATIVE RISK ANALYSIS DEPARTMENT WEATHER NORMALIZED?

A. Yes. All of the information provided by Quantitative Risk Analysis Department has been adjusted for the effects of weather using the same methodology as was used in the 2022 Phase I.

F. <u>CCOSS Model</u>

Q. PLEASE BRIEFLY DESCRIBE THE LAYOUT OF THE CCOSS IN ATTACHMENT DSK-1.

A. Table DSK-D-5 below contains a summary of the Company's CCOSS presentation:

TABLE DSK-D-5
Summary of CCOSS Presentation

Attachment DSK-1	Description
Page 1	• Table of Contents
Page 2	• Summary of the revenue requirements by specific cost function, as determined by the test year cost of service
Pages 3 through 4	• Summary of the customer sales and load data used to determine the demand and energy allocators
Page 5	• Contains the allocation factors for the Probability of Dispatch – Peak Hours method
Page 6	• Contains the non-coincident peak demand allocation factors used to allocate distribution costs
Page 7	• Provides a summary of the allocation factors from the previous pages
Pages 8 through 18	• Contains the actual allocation of the individual functional revenue requirement amounts to the various major customer classes
Page 19	• Summary of allocated total revenue requirements that displays the revenue requirements separately by customer costs, system capacity costs, and energy costs
Page 20	• Provides the allocation of DSM and EAP[16] revenue requirements to each major customer class using a revenue allocation factor and shows the total revenue requirement for each rate class

Q. IS THE COMPANY PROVIDING THE CCOSS MODEL IN EXECUTABLE FORMAT?

A. Yes. The Company is providing an executable version of its CCOSS model in Excel® format that performs the class cost of service study calculations. This is the CCOSS that is provided as Attachment DSK-1.

[16] "EAP" refers to the Electric Affordability Program. EAP amounts shown in Attachment DSK-1 do not reflect the proposed EAP levels being considered in Proceeding No. 23AL-0176E.

IV. ANALYSIS OF CCOSS RESULTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss results of the CCOSS analysis and the primary drivers of the changes in class cost responsibilities between the 2020 Phase II and this proceeding.

A. Summary of CCOSS Results

Q. PLEASE SUMMARIZE THE CHANGE IN CLASS COST RESPONSIBILITIES BETWEEN THE 2020 PHASE II AND THE CCOSS IN THIS PROCEEDING.

A. In proportion to the total system, the Residential class's cost responsibility has increased since the 2020 Phase II, the Small Commercial and C&I Secondary classes' cost responsibility has decreased, and the larger C&I classes' cost responsibility is relatively unchanged. In addition, the lighting classes' cost responsibility has decreased. Table DSK-D-6 below compares the class cost responsibility resulting from the current study to the effective class revenue allocation if not for this proceeding.

TABLE DSK-D-6
Summary of Changes in Class Cost Responsibility

	Revenue Requirement ($)		% Allocation	
	Current*	Proposed	Current	Proposed
Residential	$ 1,084,746,840	$ 1,098,688,161	44.0%	44.6%
Small Commercial	$ 131,789,619	$ 122,878,532	5.3%	5.0%
C&I Secondary	$ 900,839,338	$ 905,171,575	36.6%	36.7%
C&I Primary	$ 208,424,113	$ 201,058,345	8.5%	8.2%
C&I Transmission	$ 89,866,271	$ 91,108,993	3.6%	3.7%
Street Lighting	$ 47,070,502	$ 43,831,160	1.9%	1.8%
Traffic Lighting	$ 1,460,003	$ 1,459,919	0.1%	0.1%
Total	$ 2,464,196,686	$ 2,464,196,686		

*Reflects 2022 Phase I Proposed GRSA and GRSA-E

Q. PLEASE DISCUSS THE CHANGE IN RESIDENTIAL CLASS COST RESPONSIBILITY.

A. Overall, Residential class cost responsibility has increased from 44.0 percent to 44.6 percent of the total revenue requirements. The increase is driven by a combination of load growth, which leads to higher shares of demand-based allocators, increased investment in costs that are classified as customer-related, and higher relative responsibility for those customer-related costs. As discussed in more detail below, the use of the POD-PH allocation methodology does mitigate the overall increase in the Residential class's relative cost responsibility.

Q. PLEASE EXPLAIN HOW THE INCREASED INVESTMENT IN CUSTOMER-RELATED COSTS AND HIGHER RELATIVE RESPONSIBILITY FOR THOSE COSTS IMPACTS THE COST RESPONSIBILITY OF THE RESIDENTIAL CLASS.

A. With the allocation of customer-related costs being highly dependent on the relative number of customers in each class, the increase in customer-related investment falls disproportionately on the Residential class because it is the largest customer class (by number of customers). Further, the Residential class saw the highest growth in customers since the August 2019 Test Year (approximately 5.6 percent) further increasing its relative share for customer-weighted allocators. Finally, deployment of Advanced Meters has altered the weightings for metering and customer accounting, shifting some costs to Residential due to Advanced Meters having slightly higher weightings and the Residential class receiving the bulk of Advanced Meters thus far.

Q. PLEASE DISCUSS THE CHANGE IN SMALL COMMERCIAL CLASS COST RESPONSIBILITY.

A. Small Commercial class cost responsibility has decreased from 5.3 percent to 5.0 percent of the total revenue requirements. The decrease is driven partly by reduced class load, which is 4.6 percent lower than amounts underlying the 2020 Phase II. The Small Commercial class also has a smaller responsibility for production, transmission and distribution substation costs under the POD-PH methodology than would be the case under the 4CP-AED methodology. The Small Commercial class is also receiving a smaller share of the customer-related costs due to changes in customer (or meter) weightings.

Q. PLEASE DISCUSS THE CHANGE IN C&I SECONDARY CLASS COST RESPONSIBILITY.

A. C&I Secondary class cost responsibility has increased from 36.6 percent to 36.7 percent of the total revenue requirements. The slight increase is caused by a higher cost allocation of production, transmission, and distribution substation costs under the new POD-PH allocation methodology (as compared to the 4CP-AED method), but is partly offset by reduced class load, which shrunk 3.5 percent since the August 2019 Test Year. The allocation of primary distribution costs to the C&I Secondary class also increased due to higher class NCP demands.

Q. PLEASE EXPLAIN THE CHANGE IN C&I PRIMARY CLASS COST RESPONSIBILITY.

A. C&I Primary class cost responsibility has decreased from 8.5 percent to 8.2 percent of the total revenue requirements. The decrease in C&I Primary class cost responsibility is driven by lower allocated primary distribution costs, which is due to relatively lower class NCP demands in proportion to total NCP demands. The allocation of production, transmission and distribution substation costs to the C&I Primary class saw a slight increase due to a combination of load growth and use of the new POD-PH allocator.

Q. PLEASE EXPLAIN THE CHANGE IN C&I TRANSMISSION CLASS COST RESPONSIBILITY.

A. C&I Transmission class cost responsibility has increased from 3.6 percent to 3.7 percent of the total revenue requirements. The increased in overall cost allocation is due to an increased allocation of production, transmission, and distribution substation costs, which is driven by class load growth of 5.3 percent and the new methodology for allocating these costs. The allocation of customer-related costs decreased, which served to offset the increase from allocated production-related costs.

Q. WHAT IS CAUSING THE CHANGES IN RELATIVE CLASS COST RESPONSIBILITIES?

A. The changes in relative class cost responsibilities in this proceeding generally are due to three factors: (1) changes to the relative mix of functionalized costs; (2) changes in the relative size of each class; and (3) use of different cost allocation methodologies. I discuss each of these factors below.

B. Factors Contributing to Changes in Relative Class Cost Responsibilities

1. Functionalized Costs

Q. HOW HAVE THE FUNCTIONALIZED REVENUE REQUIREMENTS CHANGED SINCE THE 2020 PHASE II?

A. Table DSK-D-7 summarizes the changes to functionalized base rate revenue requirements since the Company's 2020 Phase II, grouped by allocation methodology. Importantly, the change in base rate revenue requirements reflects the transition of costs from riders to base rate recovery in addition to increases to the overall cost of service.

TABLE DSK-D-7
Summary of Changes in Functionalized Revenue Requirements

Functionalized Costs	Allocation Methodology	Functionalized Rev. Req. 2020 Ph.2	Functionalized Rev. Req. Current Ph.2	$ Difference	% Difference
Gen, Tran, & Dist. Subs.	4CP-AED, POD-PH	$ 961,104,063	$ 1,164,909,450	$ 203,805,387	21%
Production Energy	kWh, POD-PH	$ 222,012,383	$ 289,391,754	$ 67,379,371	30%
Primary Dist.	NCP	$ 331,429,668	$ 552,921,675	$ 221,492,007	67%
Secondary Dist.	NCP / SMD	$ 91,239,285	$ 141,629,646	$ 50,390,361	55%
Customer-Related	Wtd. Customers	$ 105,266,885	$ 177,428,182	$ 72,161,297	69%
Lighting	Direct Assigned	$ 27,890,118	$ 36,758,828	$ 8,868,710	32%
DSM & EAP	Revenue	$ 96,159,533	$ 101,157,151	$ 4,997,618	5%
Total		$ 1,835,101,935	$ 2,464,196,685	$ 629,094,751	34%

Q. HOW DOES THE CHANGE IN FUNCTIONALIZED REVENUE REQUIREMENTS IMPACT CLASS COST RESPONSIBILITIES?

A. Each class's cost responsibility varies for each category of functionalized revenue requirements. To take an extreme example: the C&I Primary and C&I Transmission classes are not responsible for any of the costs of the secondary distribution system, but they are responsible for production and transmission costs. If the Company only invested in the secondary distribution system between Phase II proceedings and everything else remained constant, the C&I Primary and C&I Transmission classes would not see an increase in base rates because they are not responsible for the costs of the secondary distribution system. This demonstrates that the relative investment across different functions does impact resulting cost responsibility.

2. <u>Relative Size of Each Class</u>

Q. HOW HAS THE RELATIVE SIZE OF EACH CUSTOMER CLASS CHANGED SINCE THE AUGUST 2019 TEST YEAR USED IN THE 2020 PHASE II?

A. We have continued to see growth in the Residential class, with the Test Year reflecting over 70,000 more Residential customers than the August 2019 Test Year. This growth has resulted in absolute increases in class energy usage (kWh), NCP, and usage during the 4CP. That absolute growth, however, does not necessarily translate into higher allocation factors.

Q. WHY DOES ABSOLUTE GROWTH IN UNDERLYING USAGE NOT NECESSARILY TRANSLATE TO A LARGER ALLOCATION FACTOR?

A. Allocation factors measure relative relationships, not absolute values. So, if two classes both see absolute increases, but one has a relatively larger increase, then its share of an allocation factor will increase.

Q. HOW DOES THIS TRANSLATE TO EACH CLASS'S SHARE OF DIFFERENT ALLOCATION FACTORS?

A. Table DSK-D-8 compares each class's relative share of the major cost allocation factors used in the Company's 2020 Phase II. As shown below, the Residential class has a larger 4CP-AED and total weighted customer allocations, but smaller NCP and average of the class NCP and the sum of individual customers' maximum demands allocators.

TABLE DSK-D-8
Comparison of Allocation Factors

Prod/Tran Capacity Allocation

	2020 Ph.2 4CP-AED	Current Ph.2 4CP-AED	Change
Residential	42.9%	46.1%	3.2%
Small Commercial	5.1%	4.8%	-0.3%
C&I Secondary	38.0%	36.1%	-1.9%
C&I Primary	8.8%	8.0%	-0.8%
C&I Transmission	4.9%	4.7%	-0.1%

Primary Dist. Allocation

	2020 Ph.2 NCP	Current Ph.2 NCP	Change
Residential	45.8%	44.6%	-1.2%
Small Commercial	5.4%	5.5%	0.1%
C&I Secondary	39.8%	41.6%	1.8%
C&I Primary	8.4%	7.8%	-0.6%
C&I Transmission	0.0%	0.0%	N/A

Secondary Dist. Allocation

	2020 Ph.2 NCP / SMD	Current Ph.2 NCP / SMD	Change
Residential	58.2%	57.1%	-1.0%
Small Commercial	5.5%	5.4%	-0.2%
C&I Secondary	35.8%	37.1%	1.3%
C&I Primary	0.0%	0.0%	N/A
C&I Transmission	0.0%	0.0%	N/A

Total Weighted Customer Allocation

	2020 Ph.2 Wtd. Cust.	Current Ph.2 Wtd. Cust.	Change
Residential	54.6%	57.6%	3.0%
Small Commercial	8.9%	6.5%	-2.4%
C&I Secondary	12.0%	15.4%	3.4%
C&I Primary	1.7%	2.0%	0.3%
C&I Transmission	1.9%	1.3%	-0.5%

3. Allocation Methodologies

Q. HOW DOES THE USE OF THE POD-PH ALLOCATION METHODOLOGY IMPACT CLASS COST RESPONSIBILITIES?

A. Replacing the 4CP-AED method with the POD-PH method reduces the Residential class cost responsibility from 46.0 percent to 44.6 percent, or approximately $35.2 million. Conversely, each of the C&I classes see greater cost responsibilities under the POD-PH method as shown in Table DSK-D-9.

TABLE DSK-D-9
Comparison of Changes in Class Cost Responsibility Using 4CP-AED

	Revenue Requirement ($)		% Allocation	
	POD-PH	4CP-AED	POD-PH	4CP-AED
Residential	$ 1,098,688,161	$ 1,133,868,666	44.6%	46.0%
Small Commercial	$ 122,878,532	$ 125,714,222	5.0%	5.1%
C&I Secondary	$ 905,171,575	$ 890,910,120	36.7%	36.2%
C&I Primary	$ 201,058,345	$ 185,601,608	8.2%	7.5%
C&I Transmission	$ 91,108,993	$ 80,734,666	3.7%	3.3%
Street Lighting	$ 43,831,160	$ 46,022,090	1.8%	1.9%
Traffic Lighting	$ 1,459,919	$ 1,345,315	0.1%	0.1%
Total	$ 2,464,196,686	$ 2,464,196,686		

Q. WHY DOES THE USE OF THE POD-PH ALLOCATOR HAVE A LARGE IMPACT ON CLASS COST RESPONSIBILITY?

A. As shown in Table DSK-D-10 below, approximately 59 percent of the Company's total revenue requirement is allocated using the POD-PH allocator.[17] As a result, the choice of allocation methodology for production, transmission and distribution substation costs is an important one. For the reasons discussed above and by Mr. Wishart, we believe use of the POD-PH allocator is appropriate in this proceeding.

[17] In the 2020 Phase II, the 4CP-AED allocator was only not used for production energy.

TABLE DSK-D-10
Revenue Requirements by Allocation Methodology

Functionalized Costs	Allocation Methodology	Rev. Req.	% of Total
Gen, Tran, & Dist. Subs.	4CP-AED, POD-PH	$ 1,164,909,450	47%
Production Energy	kWh, POD-PH	$ 289,391,754	12%
Primary Dist.	NCP	$ 552,921,675	22%
Secondary Dist.	NCP / SMD	$ 141,629,646	6%
Customer-Related	Wtd. Customers	$ 177,428,182	7%
Lighting	Direct Assigned	$ 36,758,828	1%
DSM & EAP	Revenue	$ 101,157,151	4%
Total		$ 2,464,196,685	

Q. **DOES THE USE OF SUM OF INDIVIDUAL MAXIMUM DEMANDS TO ALLOCATE SERVICE LATERAL COSTS HAVE A MUCH SMALLER IMPACT ON CLASS COST RESPONSIBILITIES?**

A. Yes. Service laterals account for less than two percent of the total Test Year revenue requirements, so the change in allocation factor has a very small effect on class cost responsibilities, primarily shifting costs from the Small Commercial class to the C&I Secondary class. Table DSK-D-11 below summarizes the change in allocation since the 2020 Phase II rate case.

TABLE DSK-D-11
Comparison of Changes in Service Lateral Allocation

Service Laterals Allocation			
	2020 Ph.2 Wtd. Cust.	Current Ph.2 Wtd. Cust.	Change
Residential	65.9%	66.0%	0.2%
Small Commercial	11.0%	4.9%	-6.1%
C&I Secondary	23.2%	29.1%	5.9%
C&I Primary	0.0%	0.0%	N/A
C&I Transmission	0.0%	0.0%	N/A

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

Statement of Qualifications
Derek S. Klingeman

Derek Klingeman is a Principal Pricing Analyst for Xcel Energy's Colorado jurisdiction. As an analyst in the Pricing and Planning department his responsibilities include quantitative analyses, cost allocation, and rate design, in addition to policy support on a number of Colorado regulatory issues. Mr. Klingeman started this role in April of 2021.

Prior to taking his current position, Mr. Klingeman worked as a consultant for NewGen Strategies and Solutions where he advised on utility cost of service and rate design and provided various financial modeling support for municipal electric utilities across the country. Derek has a Bachelor of Science degree in Finance from the University of New Mexico, where he graduated summa cum laude, and a Master of Science degree in Mineral and Energy Economics from the Colorado School of Mines.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE NO. 1923-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO RESET THE GENERAL RATE SCHEDULE ADJUSTMENTS, TO PLACE INTO EFFECT REVISED BASE RATES, AND TO IMPLEMENT OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE JUNE 15, 2023	**) PROCEEDING NO. 23AL-XXXXE**

AFFIDAVIT OF DEREK S. KLINGEMAN ON BEHALF OF PUBLIC SERVICE COMPANY OF COLORADO

I, Derek S. Klingeman, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 9 day of May, 2023.

Derek S. Klingeman
Principal Pricing Analyst

Subscribed and sworn to before me this 9TH day of May, 2023.

Notary Public

My Commission expires 07-29-2024

GINA GARGANO-AMARI
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164028888
MY COMMISSION EXPIRES 07/29/2024