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

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IN THE MATTER OF ADVICE NO. 1835-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO ELIMINATE THE CURRENTLY EFFECTIVE GENERAL RATE SCHEDULE ADJUSTMENTS TO PLACE INTO EFFECT REVISED BASE RATES AND OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE NOVEMBER 19, 2020	)	**PROCEEDING NO. 20AL-______E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF DOLORES R. BASQUEZ</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 19, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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LIST OF ATTACHMENTS

Attachment DRB-1	12 Months Ended ("ME") August 2019 Functional Allocation Study - Adjusted
Attachment DRB-2	12 ME August 2019 Test Year Regulatory Information Systems ("RIS") Class Cost of Service Study ("CCOSS")
Attachment DRB-3	12 ME August 2019 CP, NCP and Sum of Individual Maximum Demand Data

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2009 Phase II	Proceeding No. 09AL-299E
2013 TY CCOSS – 2016 Phase II	2013 TY CCOSS Approved in 2016 Phase II Rate Case – Proceeding No. 16AL-0048E
2019 TY	Test Year – 12 ME August 31, 2019
2019 Phase I Rate Case	2019 Phase I Electric Rate Case, Proceeding No. 19AL-0268E
4CP-AED	Four Coincident Peak – Average and Excess Demand
Adjusted Revenue Requirement	Adjusted Revenue Requirement for use in the CCOSS
AED	Average and Excess Demand
AGIS	Advanced Grid Intelligence & Security
C&I	Commercial and Industrial
COS	Cost of Service
CCOSS	Class Cost of Service Study
CCOSS Stakeholder Meetings	CCOSS and S&F Related Stakeholder Meetings
CEC	Colorado Energy Consumers
Climax	Climax Molybdenum Company
CP	Coincident Peak
CPUC or Commission	Colorado Public Utilities Commission
DI	Demand Interval
DSM	Demand-Side Management
EAP	Electric Affordability Program

Acronym/Defined Term	Meaning
ECA	Electric Commodity Adjustment
Final COS	Final Cost of Service Study
GRSA	General Rate Schedule Adjustment
GRSA-E	General Rate Schedule Adjustment - Energy
IDR	Interval Data Recorder
kV	Kilovolt
kWh	Kilowatt hour
ME	Months Ended
NCP	Non-Coincident Peak Demand
OCC	Office of Consumer Counsel
Prior Phase II Proceedings	2009 Phase II and 2013 TY CCOSS – 2016 Phase II
Public Service or Company	Public Service Company of Colorado
RIS	Regulatory Information System
RESA	Renewable Energy Standard Adjustment
Rush Creek Wind Project Proceeding	Proceeding No. 16A-0117E
Schedule PG	Primary General
Schedule PST	Primary Standby Service
Schedule PTOU	Primary Time-of-Use
Walmart	Walmart Stores, Inc. and Sam’s West, Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dolores R. Basquez. My business address is 1800 Larimer Street, 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") as a Pricing Consultant in Public Service's Rates and Regulatory Affairs Department.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As a Pricing Consultant, I am responsible for developing cost allocation studies as well as rate design, financial, and rate-related analyses for Public Service. A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present and sponsor the electric Class Cost of Service Study ("CCOSS"). The CCOSS allocates the revenue requirement established by the Colorado Public Utilities Commission ("CPUC" or "Commission") in the Company's last Phase I rate case, Proceeding No. 19AL-0268E ("2019 Phase I Rate Case") among Public Service's major customer classes.[1] The Company uses this allocation to establish each customer class's revenue responsibility. The Company's electric base rates proposed in this proceeding have been designed to recover each class's revenue responsibility.

In order to allocate total costs among customer classes, I developed appropriate class demand, energy, and customer allocation factors from the Company's August 2019 Test Year data.[2] In addition to presenting the CCOSS, I provide a summary of related stakeholder meetings ("CCOSS Stakeholder Meetings") held pursuant to the Non-Unanimous Comprehensive Settlement Agreement approved in Proceeding No. 16AL-0048E (the "2016 Phase II").[3]

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[1] A revenue requirement of $1,828,985,415 was approved by Commission Decision No. C20-0096 as modified by Decision No. C20-0505 in Proceeding No. 19AL-0268E, to be collected through a GRSA and GRSA-E. The final cost of service study ("Final COS") was included as Attachment 1 to Advice No. 1832-Electric, the compliance advice letter filing made on August 14, 2020 for the 2019 Phase I Rate Case. *See* Proceeding No. 20AL-0334E (the "August 2020 Phase I Compliance Filing").

[2] This reference is to the Company's 2019 test year (the 12 months ended August 31, 2019 ("August 2019 Test Year") approved by the Commission in the 2019 Phase I Rate Case.

[3] Decision No. C16-1075, Attachment A, page 19 ("Three Case Settlement"). While Decision No. C16-1165 modified Decision No. C16-1075, those modifications did not affect the approved portions of the Three Case Settlement affecting the CCOSS and the referenced stakeholder requirements.

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

A. Yes, I am sponsoring Attachments DRB-1, DRB-2, and DRB-3. Attachment DRB-1 is the Adjusted Functional Allocation Study prepared by the Company. Attachment DRB-2 is the CCOSS the Company is presenting for purposes of this case and Attachment DRB-3 are the CP, Non-Coincident Peak Demand (“NCP”) and Sum of Individual Maximum Demands that are used in the CCOSS. Attachments DRB-2 and DRB-3 were prepared by me or under my direct supervision.

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

A. I recommend the Commission approve the Company’s proposed CCOSS, included as Attachment DRB-2 to my Direct Testimony.

II. OVERVIEW OF THE CCOSS

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

A. In this section, I explain the purpose of the CCOSS, provide the results of the CCOSS, and provide an overview of the costs that form the basis of the CCOSS.

Q. WHAT IS THE PURPOSE OF THE CCOSS?

A. The purpose of the CCOSS is to allocate the total revenue requirement approved in the Company's 2019 Phase I Rate Case among its major customer classes. The CCOSS sets forth the revenue requirements by major customer class, which are used in developing the Company's proposed base rates. In other words, the CCOSS measures the contribution each class makes to the Company's overall revenue requirement approved in the Company's 2019 Phase I Rate Case.

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. Table DRB-D-1 below summarizes the present distribution of the 2019 Phase I Rate Case revenue requirement [Column B] and the cost-based distribution of the 2019 Phase I Rate Case revenue requirement [Column E]. The amounts in Column B reflect present base rate revenue as well as revenue being collected through the current GRSA and GRSA-E.

Table DRB-D-1
Present and Cost-Base Revenue Distribution

		Present Rates			Proposed Rates			
	(A) Customer Class	**(B) Adjusted Test Year Base Rate Revenue at Present Rates**	**(C) ROR at Present Rates**	**(D) Relative Rate of Return at Present Rates**	**(E) Proposed Revenue Distribution**	**(F) ROR at Proposed Rates**	**(G) Base Rate Revenue Change**	**(H) % Base Rate Revenue Increase/ Decrease**
1	Residential	$731,876,356	5.44%	0.78	$803,692,037	6.97%	$71,815,681	9.81%
2	Small Commercial	$98,619,596	6.93%	0.99	$98,817,239	6.97%	$197,643	0.20%
3	C&I Secondary	$719,488,007	8.10%	1.16	$672,983,214	6.97%	($46,504,793)	-6.46%
4	C&I Primary	$156,817,568	7.72%	1.11	$149,913,713	6.97%	($6,903,856)	-4.40%
5	C&I Transmission	$75,705,662	9.73%	1.40	$65,523,594	6.97%	($10,182,068)	-13.45%
6	Street and Area Lighting	$44,800,089	12.62%	1.81	$36,441,788	6.97%	($8,358,301)	-18.66%
7	Traffic Signal Lighting	$1,194,658	8.01%	1.15	$1,130,351	6.97%	($64,307)	-5.38%
8	Sub Total	$1,828,501,935	6.97%	1.00	$1,828,501,935	6.97%	($0)	0.00%
9	Interconnection charges	$ 483,480			$ 483,480			
10	TOTAL	$1,828,985,415			$1,828,985,415			

Q. PLEASE DESCRIBE THE PORTION OF THE TABLE LABELED "PRESENT RATES."

A. Collectively, Columns B, C, and D summarize the recovery of costs under the General Rate Schedule Adjustment ("GRSA") mechanisms established in the 2019 Phase I Rate Case by each major customer class to the cost to provide service to each customer class. As shown in Column C, some classes are below or above the Commission-approved overall average rate of return of 6.97 percent. Column D presents each class's performance relative to the system average rate of return.

Q. PLEASE DESCRIBE THE PORTION OF THE TABLE LABELED "PROPOSED RATES."

A. Collectively, Columns E, F, G, and H summarize the revenue distribution by major customer class that the Company is proposing to implement in this Phase II proceeding. Specifically, the revenue distribution in Column E is the result of the cost-based allocations performed in the CCOSS, which are consistent with the allocation methodologies the Company has employed in its most recent

Phase II rate cases. As shown in Column F, this cost-based revenue distribution brings each class to its full cost of service, or revenue requirement, including a return consistent with the Commission's authorized return. When revenue responsibility equals cost responsibility, each major customer class equitably shares in the overall rate of return of 6.97 percent approved in the Company's 2019 Phase I Rate Case. Column G shows the change in revenue responsibility needed to set each class's revenue responsibility equal to its cost responsibility (Column E minus Column B). Column H shows this base rate revenue increase or decrease by major customer class on a percentage basis.

Q. DOES THE CHANGE IN CLASS REVENUE RESPONSIBILITY AS A RESULT OF THE CCOSS CHANGE THE OVERALL BASE RATE REVENUE REQUIREMENT?

A. No. As shown on line 10 of Table DRB-D-1, the overall electric base rate revenue requirement is unchanged as a result of the CCOSS.

Q. ARE ANY ADJUSTMENTS MADE TO THE TOTAL BASE RATE REVENUE REQUIREMENT IN THE CCOSS?

A. Yes. The CCOSS must also incorporate the allocation of the Company's Commission-approved Electric Affordability Program ("EAP").[4] Table DRB-2 below summarizes the allocation of the EAP costs and the resulting total class revenue requirements.

[4] The Company's 2009 Phase II established an EAP of $4 million, which was continued in the 2016 Phase II. *See* 2009 Electric Phase II, Decision No. C10-0286, at paragraph 111 on page 37; Three Case Settlement at Section X. On March 5, 2020, the Company filed Advice No. 1819 – Electric to modify the EAP to $6.6 million, which went in effect on April 5, 2020 by operation of law. *See* Proceeding No. 20AL-0090E. As a result, the Company has included an additional $6.6 million in the CCOSS for the EAP.

Table DRB-D-2
Summary of Allocated Revenue Requirements

	Proposed Revenue Requirement	Proposed Allocation of EAP Costs	Total Adjusted Revenue Requirement	Percent of Allocated Adjusted Revenue Requirement
Residential	$ 803,692,037	$ 2,900,936	$ 806,592,973	43.9%
Small Commercial	$ 98,817,239	$ 356,682	$ 99,173,921	5.4%
C&I Secondary	$ 672,983,217	$ 2,429,141	$ 675,412,358	36.8%
C&I Primary	$ 149,913,713	$ 541,115	$ 150,454,828	8.2%
C&I Transmission	$ 65,523,594	$ 236,508	$ 65,760,102	3.6%
Street and Area Lighting	$ 36,441,788	$ 131,537	$ 36,573,325	2.0%
Traffic Signal Lighting	$ 1,130,351	$ 4,080	$ 1,134,431	0.1%
Interconnection Charges	$ 483,480	$ -	$ 483,480	0.0%
Total	$ 1,828,985,418	$ 6,600,000	$ 1,835,585,418	100.0%

Q. HOW IS THE TOTAL CLASS REVENUE REQUIREMENT UTILIZED IN THIS PHASE II PROCEEDING?

A. The total class revenue requirement shown in Table DRB-2 forms the revenue targets for which the Company’s proposed base rates are designed to recover, by class. Company witness Mr. Alexander G. Trowbridge sponsors the Company’s proposed rates in this Phase II Rate Case and both Mr. Trowbridge and Company witness Mr. Steven W. Wishart discuss the rate design process in more detail in their Direct Testimonies.

III. THE COST ALLOCATION PROCESS

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

A. In this section, I describe the three steps of allocating costs to classes.

Q. WHAT ARE THE STEPS IN THE COST ALLOCATION PRCESS?

A. There are three steps in the cost allocation process: functionalization, classification, and allocation. The end result is a revenue requirement by major customer class that is used to design rates. For Public Service's electric department, the functionalization of costs occurred the 2019 Phase I Rate Case, specifically the cost of service study prepared by Company witness Ms. Deborah A. Blair, as reflected in the Final COS.[5] However, as I describe later in my Direct Testimony, the Company is proposing to make a minor refinement to the functionalization of certain Advanced Grid Intelligence & Security ("AGIS") - related costs.

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, 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.

[5] The Final COS was included as Attachment 1 to the August 2020 Phase I Compliance Filing.

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 during the test year; (2) 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 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; demand charges, which are based on kilowatts and applicable to some but not all rate schedules; and services and facilities charges, which are typically 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. However, for Public Service, these costs are recovered through the Electric Commodity Adjustment ("ECA") and not in base rates. The CCOSS allocates non-fuel energy-related costs recovered in base rates. Examples of these non-fuel costs include the costs of chemicals, water, and ash handling. These costs vary with the amount of electric energy produced. As I discuss in more detail later in my Direct Testimony, Public Service has an increasing amount of non-fuel energy related costs in base rates attributable to the Rush Creek Wind Project that began commercial operation during the August 2019 Test Year and was included in base rates in the 2019 Phase I Rate Case.

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

A. Yes. The costs of generation, transmission, and distribution plant are examples of costs that are generally considered capacity-related costs. The Company must design its bulk power and delivery systems with sufficient capacity to produce and deliver energy during periods when system demand is at its highest. Even with the addition of the Rush Creek Wind Project in the August 2019 Test Year and the increasing amount of energy-related costs on the system, the majority of system costs relate to generation, transmission, and distribution plant in service and therefore the majority of system costs are capacity 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 DESCRIBE THE PROCESS OF ALLOCATING COSTS AMONG MAJOR CUSTOMER CLASSES.

A. The allocation step involves the assignment of classified costs to various customer classes. One of the primary goals of a CCOSS is to develop class cost allocation factors that accurately reflect cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. For example, meter reading costs are generally allocated to various customer classes based on an allocation factor that is derived by weighting the meter type by the number of customers for each type of meter installed. Other allocators are used to allocate energy-related or demand-related costs.

IV. COMPANY'S IMPLEMENTATION OF THE COST ALLOCATION PROCESS

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

A. In this section, I describe the Company's implementation of the cost allocation process, including the major customer classes used, the aggregation of individual electric service schedules, the costs directly assigned in the CCOSS, and the Company's implementation of the above-described three-step cost allocation process.

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

A. Table DRB-D-3 below summarizes the Company's three-step class cost allocation process.

Table DRB-D-3
Summary of Cost Allocation Process

Step One	**Step Two**			**Step Three**
Functionalization	**Classification**			**Allocation**
	Capacity Related	Energy Related	Customer Related	
Functions:				
PRODUCTION				
Steam Production	X			4CP-AED
Hydro Production	X			4CP-AED
Comb Turbine Production	X			4CP-AED
Purchased Capacity	X			4CP-AED
Transmission Interconnect	X			4CP-AED
Production Energy		X		Energy
TRANSMISSION				
Transmission System	X			4CP-AED
Transmission by Others	X			4CP-AED
DISTRIBUTION				
Distribution Substations	X			4CP-AED/Direct Assignment
Primary Distribution System	X			Annual NCP
Secondary Distribution System	X			Secondary NCP
Service Lateral			X	Weight Factors
Metering			X	Weight Factors
Lighting	X	X	X	Direct Assignment
CUSTOMER OPERATIONS				
Meter Reading			X	Weight Factors
Customer Accounting			X	Weight Factors
Please note: Demand-Side Management ("DSM") is considered a function in the functionalized cost of service study (Final COS) approved in the 2019 Phase I Rate Case. Functionalization, classification and allocation for the metering function in this table is for Non-AMI meters.				

A. <u>CCOSS - Major Customer Classes</u>

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

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

- Residential General;
- 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 broad C&I Primary customer class includes Primary General Service ("Schedule PG"), Primary Standby Service ("Schedule PST"), Primary Time-of-Use Service ("Schedule PTOU"), and Special Contract Service – Regional Transportation District ("Schedule SCS-7"). Costs are not directly allocated to each of these rate schedules. Instead, costs are allocated to the broad Primary C&I customer class. In this example, the costs allocated to the C&I Primary class are then used to design rates for Schedule PG, Schedule

PST, and Schedule PTOU. Table DRB-4 below outlines what rate schedules are included in each major customer class for purposes of the CCOSS.

Table DRB-D-4[6]
Mapping of Rate Schedules to Major Customer Classes

Major Customer Class - Residential		
	Residential General	Schedule R
	Residential Demand	Schedule RD
	Residential Demand-Time Differentiated Rates	Schedule RD-TDR
	Residential Energy Time-of-Use	Schedule RE-TOU
Major Customer Class - Small Commercial		
	Commercial	Schedule C
	Non-Metered Service	Schedule NMTR
Major Customer Class - C&I Secondary		
	Secondary General	Schedule SG
	Secondary General Low-Load Factor	Schedule SGL
	Secondary General Critical Peak Pricing	Schedule SG-CPP
	Secondary Standby Service	Schedule SST
	Secondary Time-of-Use	Schedule STOU
	Secondary Photovoltaic Time-of-Use	Schedule SPVTOU
	Secondary Voltage Time-of-Use	Schedule SPVTOU
	Secondary Voltage Time-of-Use Electric Vehicle	Schedule S-EV
Major Customer Class - C&I Primary		
	Primary General	Schedule PG
	Primary General Critical Peak Pricing	Schedule PG-CPP
	Primary Standby Service	Schedule PST
	Primary Time-of-Use	Schedule PTOU
	Special Contract Service - Regional Transportation District	Schedule SCS-7
Major Customer Class - C&I Transmission		
	Transmission General	Schedule TG
	Transmission General Critical Peak Pricing	Schedule TG-CPP
	Transmission Standby Service	Schedule TST
	Special Contract Service - Regional Transportation District	Schedule SCS-8
Major Customer Class - Street and Area Lighting		
	Residential Outdoor Area Lighting	Schedule RAL
	Commercial Outdoor Area Lighting	Schedule CAL
	Parking Lot Lighting Service	Schedule PLL
	Metered Street Lighting Service	Schedule MSL
	Energy Only Street Lighting Service	Schedule ESL
	Street Lighting Service	Schedule SL
	Special Street Lighting Service	Schedule SSL
	Unincorporated Areas	Schedule SLU
	Customer-Owned Lighting Service	Schedule COL
Major Customer Class - Traffic Signal Lighting		
	Metered Intersection Service	Schedule MI
	Traffic Signal Lighting	Schedule TSL

[6] Newly approved Schedule R-OO is not included on this CCOSS Table as it will not be effective until January 1, 2021.

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

A. Yes, the Residential Demand rate schedule is aggregated into the Residential customer class rather than being its own major customer class.

Q. WHY DID THE COMPANY MAKE THIS CHANGE?

A. There are very few customers under this Schedule, therefore, the Company believes it would be more efficient to aggregate this schedule under the Residential major customer class.

B. Direct Assignment

Q. ARE ALL COSTS ALLOCATED IN THE CCOSS?

A. No. There are some costs that are directly assigned.

Q. PLEASE EXPLAIN DIRECT COST ASSIGNMENT.

A. A cost is directly assigned if it can be specifically attributed to a specific major customer class or an individual customer.

Q. PLEASE SUMMARIZE THE COSTS THAT WERE DIRECTLY ASSIGNED IN THE CCOSS PRESENTED IN THIS PROCEEDING.

A. In the CCOSS, costs were directly assigned in two circumstances. 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 Service and Facility Charge. In addition, the lighting classes are directly assigned lighting equipment.

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. 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 also not allocated primary distribution costs.

C. Functionalization

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

A. As I described previously, the activity of functionalizing costs for Public Service's electric department was largely completed in the 2019 Phase I Rate Case. In the cost of service study presented by Ms. Blair, 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. HAVE YOU MADE ANY ADJUSTMENTS TO THE FUNCTIONALIZATION THAT WAS PROVIDED IN THE 2019 PHASE I RATE CASE?

A. Yes. In the Final COS, costs associated with certain AGIS projects were inadvertently functionalized among production, transmission, and distribution rather than just distribution. Attachment DRB-1 contains the Company's Adjusted Functionalization Study, which was adjusted from the Final COS included with the Phase I Compliance Filing in order to re-functionalize certain AGIS costs as proposed by the Company in this proceeding.

Q. PLEASE IDENTIFY THE COSTS THAT HAVE BEEN REFUNCTIONALIZED.

A. Table DRB-D-5 below identifies the AGIS costs included in the Company's final, Commission-approved revenue requirement and the proposed re-functionalization of some of those costs.

Table DRB-D-5
AGIS Re-functionalization

	Record Type	Account	Functionalization (COS)	Functionalization (revised)
1	AGIS ADMS (Non-CPCN)	303004-Intg Misc Computr Softwar	Production, Transmission, Distribution Plant	Distribution - Primary/Secondary
2	AGIS ADMS (Non-CPCN)	391004-General Info Sys Computer	Production, Transmission, Distribution Plant	Distribution - Primary/Secondary
3	AGIS ADMS (Non-CPCN)	397000-General Communication E	Production, Transmission, Distribution Plant	Distribution - Primary/Secondary
4	AGIS ADMS (Non-CPCN)	58800-Dist Oper Misc Exp	Distribution - Primary/Secondary	Distribution - Primary/Secondary
5	AGIS ADMS (Non-CPCN)	59800-Dist Mtce of Dist Plant	Distribution - Primary/Secondary	Distribution - Primary/Secondary
6	AGIS Adv Grid Other (Non CPCN)	58800-Dist Oper Misc Exp	Distribution - Primary/Secondary	Distribution - Primary/Secondary
7	AGIS Adv Grid/Other (Non-CPCN)	394000-General Tools & Shop Equi	Production, Transmission, Distribution Plant	Distribution - Primary/Secondary
8	AGIS AMI (CPCN)	370000E-Distribution Meter	Distribution - Meters	Distribution - Secondary
9	AGIS AMI (CPCN)	391004-General Info Sys Computer	Production, Transmission, Distribution Plant	Distribution - Secondary
10	AGIS AMI (CPCN)	394000-General Tools & Shop Equi	Production, Transmission, Distribution Plant	Distribution - Secondary
11	AGIS AMI (CPCN)	58800-Dist Oper Misc Exp	Distribution - Meters	Distribution - Secondary
12	AGIS AMI (CPCN)	59700-Dist Mtc of Meters	Distribution - Meters	Distribution - Secondary
13	AGIS FAN (CPCN)	58800-Dist Oper Misc Exp	Distribution - Primary	Distribution - Primary
14	AGIS FAN (CPCN)	59800-Dist Mtce of Dist Plant	Distribution - Primary	Distribution - Primary
15	AGIS FAN (Non-CPCN)	361000E-Str & Improv	Distribution - Substations	Distribution - Primary
16	AGIS FAN (Non-CPCN)	397000-General Communication E	Production, Transmission, Distribution Plant	Distribution - Primary
17	AGIS FAN (Non-CPCN)	58800-Dist Oper Misc Exp	Distribution - Primary	Distribution - Primary
18	AGIS FAN (Non-CPCN)	59800-Dist Mtce of Dist Plant	Distribution - Primary	Distribution - Primary
19	AGIS FLISR (Non-CPCN)	361000E-Str & Improv	Distribution - Substations	Distribution - Primary
20	AGIS FLISR (Non-CPCN)	397000-General Communication E	Production, Transmission, Distribution Plant	Distribution - Primary
21	AGIS FLISR (Non-CPCN)	58800-Dist Oper Misc Exp	Distribution - Primary	Distribution - Primary
22	AGIS FLISR (Non-CPCN)	59300-Dist Mtc of Overhead Lines	Distribution - Primary	Distribution - Primary
23	AGIS IVVO (CPCN)	361000E-Str & Improv	Distribution - Substations	Distribution - Secondary
24	AGIS IVVO (CPCN)	362000E-Other Eq	Distribution - Substations	Distribution - Secondary
25	AGIS IVVO (CPCN)	397000-General Communication E	Production, Transmission, Distribution Plant	Distribution - Secondary
26	AGIS IVVO (CPCN)	58800-Dist Oper Misc Exp	Distribution - Primary/Secondary	Distribution - Secondary
27	AGIS IVVO (CPCN)	59300-Dist Mtc of Overhead Lines	Distribution - Primary/Secondary	Distribution - Secondary

Q. PLEASE EXPLAIN WHY THESE COSTS WERE NOT FUNCTIONALIZED AS DISTRIBUTION IN THE FINAL COS.

A. The projects in question are recorded as part of FERC Accounts that contain other, non-AGIS related plant. In preparing the Final COS, the AGIS costs were functionalized in the manner that those FERC Accounts were functionalized. For instance, AGIS software costs in FERC Account 303004 were functionalized in the Final COS as production, transmission, and distribution, rather than solely as distribution. It is appropriate to functionalize the non-AGIS costs in FERC Account 303004 as production, transmission, and distribution because non-AGIS software recorded in that account supports production-, transmission-, and distribution-related plant. However, upon further review in the CCOSS, that functionalization for the AGIS component of FERC Account 303004 was considered inconsistent with cost causation.

Q. CAN YOU DEMONSTRATE THAT THIS RE-FUNCTIONALIZATION HAS NO IMPACT ON THE OVERALL APPROVED REVENUE REQUIREMENT AMOUNT USED IN THE CCOSS IN THIS PROCEEDING?

A. Yes. As shown on Table DRB-D-6 below, the re-functionalization merely shifts costs into other functional categories without affecting the amount of the total revenue requirement.

Table DRB-D-6
AGIS Re-functionalization Adjustment to Revenue Requirements

Function	Total Revenue Requirement Prior to AGIS Re-Functionalization Adjustment* $	Total Revenue Requirement Adjustment for AGIS Re-Functionalization $	**Total Adjusted Revenue Requirement for AGIS Re-Functionalization $**
Production			
Production Capacity			
Steam Production	378,047,935	(1,364,060)	**376,683,875**
Hydro Production	22,564,551	(72,063)	**22,492,488**
Comb Turbine Production	243,588,414	(925,102)	**242,663,311**
Purchased Capacity	(5,190,362)	-	**(5,190,362)**
Transmission Interconnect	6,448,538	(29,636)	**6,418,902**
Total Production Capacity	645,459,074	(2,390,861)	**643,068,213**
Production Energy	222,463,787	(451,404)	**222,012,383**
Total Production	867,922,861	(2,842,265)	**865,080,596**
Transmission			
Transmission System	214,141,681	(899,618)	**213,242,063**
Transmission by Others	9,195,337	-	**9,195,337**
Total Transmission	223,337,018	(899,618)	**222,437,400**
Distribution			
Distribution Substations	98,091,707	(2,009,778)	**96,081,929**
Primary Distribution System	325,044,236	3,341,278	**328,385,514**
Secondary Distribution System	88,008,332	6,275,108	**94,283,439**
Service Laterals	28,892,446	15,618	**28,908,063**
Metering	40,410,070	(3,798,831)	**36,611,239**
Lighting	27,971,629	(81,511)	**27,890,118**
Total Distribution	608,418,420	3,741,883	**612,160,303**
Customer Operations			
Meter Reading	9,157,334	-	**9,157,334**
Customer Accounting	30,590,248	-	**30,590,248**
Total Customer Operations	39,747,583	-	**39,747,583**
Demand Side Management	89,559,533	-	**89,559,533**
Low Income Assistance	6,600,000	-	**6,600,000**
Total Retail Revenue Requirement	1,835,585,415	(0)	**1,835,585,415**

D. Classification

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

A. Functionalized costs are classified as capacity-related, energy-related, or customer-related. The fixed production, transmission, distribution substation, primary distribution, and secondary distribution costs were classified as capacity-related. Costs that vary with the amount of energy generated – such as the costs of water, chemicals, and ash disposal – were classified as energy-related. Costs that vary with the number of customers rather than their annual or peak loads – such as the costs of service laterals, metering, meter reading, and customer accounting – were classified as customer-related.

Q. PLEASE EXPLAIN HOW THE PRODUCTION ENERGY PORTION OF THE RUSH CREEK WIND PROJECT COSTS WERE CLASSIFIED AND ALLOCATED FOR PURPOSES OF THE COMPANY'S CCOSS IN THIS PROCEEDING.

A. The production energy portion of the Rush Creek Wind Project costs are classified as energy related and allocated on an energy basis.

Q. PLEASE EXPLAIN WHY THE PRODUCTION ENERGY PORTION OF THE RUSH CREEK WIND PROJECT COSTS WERE CLASSIFIED AS ENERGY RELATED AND ALLOCATED ON AN ENERGY BASIS.

A. First, wind generation is intermittent, and it generally does not provide the reliability that other baseload or peaking units provide to the Company's system during peak times. According to the Direct Testimony of Public Service's witness Mr. James F. Hill in the Rush Creek Wind Project Proceeding, Proceeding No. 16A-0117E ("Rush Creek Wind Project Proceeding"), at page 79, line 11, the amount of Rush Creek Wind generation that was projected to be available during system peak was about 8.2 percent (49/600 MW).

Second, the Rush Creek Wind Project costs have been allocated on an energy basis since the Company began cost recovery in December of 2018 and have continued to be allocated on an energy basis ever since. Under the

Commission-approved Settlement in the Rush Creek Wind Project Proceeding,[7] these costs were recovered through the Company's ECA through February 24, 2020, which is a cost recovery mechanism that recovers costs based on customers' energy consumption, measured in kWh. In the Company's 2019 Phase I Rate Case, the Commission authorized Public Service to recover most of the costs associated with the Rush Creek Wind Project through a General Rate Schedule Adjustment-Energy ("GRSA-E").[8] The Company began recovering authorized costs through the GRSA-E beginning on February 25, 2020, and continues to recover authorized Rush Creek Wind Project costs from customers based on their energy consumption or kWh.

Q. HAVE YOU ANALYZED RUSH CREEK GENERATION DATA FOR THE AUGUST 2019 TEST YEAR TO DETERMINE THE ACTUAL AMOUNT OF GENERATION THAT OCCURRED DURING THE COMPANY'S SYSTEM PEAKS?

A. Yes. For purposes of this proceeding, the Company has reviewed actual Rush Creek generation data during the August 2019 Test Year[9] system peaks and

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[7] *See* Three Case Settlement at pp. 15-16, approved by Decision No. C16-0958, Proceeding No. 16A-0117E, providing that "The Company in its direct case presented cost recovery of the Rush Creek Wind Project through the Electric Commodity Adjustment ("ECA") and Renewable Energy Standard Adjustment ("RESA") until such time as the Company files a base rate case following the commercial operation date of the Project….In addition, the jurisdictional cost allocation will be based on an energy allocator for the Rush Creek Wind Project." *Citing* Amended Direct Testimony of Alice K. Jackson, at 73:2 – 100:20 (filed July 8, 2016).

[8] Per the Commission's Decision in the 2019 Phase I Rate Case and the Rush Creek Settlement Agreement approved in Proceeding No. 16A-0117E, Production Tax Credits, certain capital-sharing costs, and a small amount of transmission upgrade costs are being credited or recovered through mechanisms other than the GRSA-E.

[9] Public Service reviewed actual Rush Creek generation for the summer months of June 2019 through September 2019. The months of June, July, and August 2019 are part of the August 2019 Test Year.

determined that the actual amount of Rush Creek generation available during the summer months averaged about 8.8 percent. Please see Table DRB-D-7 below. Because relatively little generation capacity is provided by the Rush Creek Wind Project during the summer months when the Company typically needs generation capacity the most, it is not appropriate to classify these costs as capacity-related.

Table DRB-D-7
Rush Creek Generation During Summer Peak

			Total Rush Creek MW:	600
Test Year Data				
Month		Peak Interval - Hour Beginning	Rush Creek Generation - MW	% of Rush Creek Generation During System Peak
6		06/18/2019 04:00 PM	44	7.3%
7		07/11/2019 04:00 PM	23	3.8%
8		08/19/2019 04:00 PM	56	9.3%
Non-Test Year Data				
9		09/02/2019 05:00 PM	89	14.8%
	Average for Summer Months			**8.83%**

E. Allocation

Q. PLEASE DESCRIBE HOW THE COMPANY ALLOCATED COSTS AMONG MAJOR CUSTOMER CLASSES IN THE CCOSS.

A. The revenue requirements for the classified costs were allocated among the major customer classes based on allocation factors developed with class customer counts, demand (kW) and energy (kWh) information from the August 2019 Test Year.

September 2019 is not a part of the August 2019 Test Year; however, the Company has included September for the referenced analysis for purposes of calculating the generation capacity during the summer period (June-September).

Q. IN GENERAL, HOW DID PUBLIC SERVICE DETERMINE THE APPROPRIATE ALLOCATION FACTORS FOR THE VARIOUS FUNCTIONALIZED AND CLASSIFIED COST COMPONENTS INCLUDED IN THE CCOSS?

A. An allocation factor should reflect the classification and functionalization of the costs being allocated. For example:

- Costs associated with producing energy are allocated in proportion to the energy consumed by each major customer class, with adjustments to account for the different level of system losses at various delivery voltages;
- Capacity costs are allocated on some measure of the peak load that each class places on the system;
- Customer-related costs are generally allocated on the basis of the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics;
- For non-AGIS meters, the cost of each type of meter installation was used to determine the allocated investment; and
- For meter reading and billing expenses, the weighting factors were derived from an analysis of the costs of meter reading and bill processing for the various types of meter installations.

Q. PLEASE EXPLAIN WHICH ALLOCATION FACTORS UTILIZE INTERNAL STUDIES REGARDING CUSTOMER-RELATED COSTS.

A. The Company completed several studies to develop weighting factors that were used in the derivation of the allocated revenue requirements for customer-related costs including: service laterals, meters, lighting equipment, meter reading, and billing and customer accounting.

Q. HOW ARE THE INTERNAL STUDIES USED?

A. The studies are used in the CCOSS model (specifically, pages 17 through 22 of Attachment DRB-2) and they form the basis of the applicable allocation factors for customer-related costs.

Q. CAN YOU EXPLAIN IN MORE DETAIL ONE OF THE INTERNAL STUDIES PREPARED FOR CUSTOMER-RELATED COSTS?

A. One of the internal studies relates to meter reading costs. Meter reading costs are driven by the type of meter installed. Meters can be broken down into three categories: (1) kWh and kWh-L ("kWh with load profile"); (2) Demand Interval ("DI") and Bridge Demand; and (3) Interval Data Recorder ("IDR"). Demand Interval, Bridge Demand and IDR meters are more complex, and IDR meters require manual meter reads. Consequently, these two types of meters entail higher meter reading costs than kWh and kWh-L meters. Therefore, to allocate meter reading costs, the Company conducted a study to determine the respective costs of reading the three types of meters on our system and developed weighting factors based on these cost differences. As an additional example, the Company applied the same methodology from the Prior Phase II Proceedings[10] to allocate service lateral costs in this proceeding. Under that methodology, service lateral costs are allocated based on each major class's

[10] Proceeding Nos. 09AL-299E and 16AL-0048E.

contribution to the sum of the individual major customer classes' annual maximum demands.

Q. WHAT ALLOCATION FACTORS UTILIZE INPUTS DEVELOPED BASED ON LOAD RESEARCH DATA?

A. The CCOSS demand allocation factors are calculated using inputs derived from load research data. Company witness Mr. Mario G. Martinez discusses how the Company collects and calculates the load research data. Attachment DRB-3 includes the load research data provided by Mr. Martinez and shows the calculation of demand data that is used to derive the various demand allocation factors. Those demand allocation factors are calculated in Attachment DRB-2, pages 7-11.

Q. WHAT ARE THE CCOSS DEMAND ALLOCATION FACTORS?

A. There are three CCOSS demand allocation factors: (1) 4CP-AED; (2) Class Annual NCP; and (3) Secondary NCP. I discuss each of these allocation factors below. Attachment DRB-2 provides the demand data used to calculate these allocation factors as well as the derivation of the allocation factors.

1. 4CP-AED

Q. WHAT IS THE 4CP-AED ALLOCATION FACTOR?

A. The 4CP-AED allocation factor stands for 4 Coincident Peak (CP) – Average and Excess Demand. This is a two-part allocation factor. The 4CP component measures class contributions to system peak loads during the four summer months of June, July, August, and September. Specifically, the 4CP component is based on the average of the class system CP demands for June, July, August, and September.[11] The AED component of the allocator allocates costs on the basis of both class energy requirements (the "Average Demand") and class contributions to system peak demand (the "Excess Demand"). The derivation of this allocation factor is shown on Page 7 of Attachment DRB-2.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE 4CP-AED ALLOCATION FACTOR.

A. The development of the 4CP-AED allocation factor is a two-step process. The first step is to calculate the average of the class CP demands during the four summer months – or the class 4CP. These averages are shown in the first column of page 7 of Attachment DRB-2. The Average Demand for each major customer class is calculated by dividing the class annual energy, adjusted for losses, by the number of hours (8,760) in the August 2019 Test Year. Each class's Average Demand is then subtracted from the class 4CP to determine the Excess Demand for that class, if any.

Q. AFTER YOU DETERMINE THE AVERAGE EXCESS DEMAND FOR EACH CUSTOMER CLASS, WHAT IS THE SECOND STEP?

A. The second step is to allocate to the major customer classes the Average Excess Demand, which is the difference between the total retail system peak and the total of the retail average demands. Any Average Excess Demand is allocated to each class using the ratio of each major customer class's Excess Demand (as

[11] The August 2019 Test Year is the 12 months ended August 2019. Therefore, the 4CP-AED allocation factor was calculated using data from the summer of 2018 (September) and 2019 (June, July and August) to represent the four summer months in the August 2019 Test Year.

explained above) to the total retail Excess Demand. The sum of a class's allocated Excess Demand and Average Demand is the 4CP-AED demand allocator for that class.

Q. WHAT COSTS ARE ALLOCATED USING THE 4CP-AED ALLOCATION FACTOR?

A. The Company allocated production, transmission, and distribution substation costs using the 4CP-AED allocation factor.

Q. WHY DOES THE COMPANY ALLOCATE THESE COSTS USING THE 4CP-AED ALLOCATION FACTOR?

A. The 4CP-AED allocation factor is consistent with cost-causation. The Company is a summer-peaking utility. Consequently, all costs driven by system peak loads should be allocated to classes based on their contributions to summer peak loads. In addition, the 4CP-AED methodology ensures there are no "free riders." For example, if the Company used the 4CP method rather than the 4CP-AED method to allocate its generation, transmission, and distribution substation costs, the Street and Area Lighting class would not pay for these assets because street are area lights are generally not being utilized during the Company's summer peaks. This would not be appropriate, because the Street and Area Lighting class uses these assets.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE USE OF THE 4CP-AED ALLOCATION FACTOR?

A. Yes. The Commission has consistently approved use of the 4CP-AED allocation factor in the Company's Prior Phase II Proceedings.

2. Class Annual NCP

Q. WHAT IS THE CLASS ANNUAL NCP ALLOCATION FACTOR?

A. The Class Annual NCP allocation factor compares each class's NCP to the total NCP. The derivation of this allocation factor is shown on Page 10 of Attachment DRB-2.

Q. WHAT COSTS ARE ALLOCATED USING THE CLASS ANNUAL NCP ALLOCATION FACTOR?

A. The Class Annual NCP allocation factor is used to allocate the costs of the primary distribution system.

Q. WHAT IS THE PRIMARY DISTRIBUTION SYSTEM?

A. The primary distribution system is made up of the 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 August 2019 Test Year, regardless of when this class peak demand occurs, to allocate primary distribution system capacity costs.

Q. WHY DOES THE COMPANY USE THE CLASS ANNUAL NCP ALLOCATION FACTOR TO ALLOCATE THE COSTS OF THE PRIMARY DISTRIBUTION SYSTEM?

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 Proceedings.

3. Secondary NCP

Q. WHAT IS THE SECONDARY NCP ALLOCATION FACTOR?

A. The Secondary NCP Allocation factor is the average of the class NCP and the sum of individual customers' annual NCP. The derivation of this allocation factor is shown on Page 10 of Attachment DRB-2.

Q. WHAT COSTS ARE ALLOCATED USING THE SECONDARY NCP ALLOCATION FACTOR?

A. The Secondary NCP Allocation factor is used to allocate the capacity-related costs of the secondary distribution system.

Q. WHAT IS THE SECONDARY DISTRIBUTION SYSTEM?

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.

Q. WHY DID THE COMPANY USE THE SECONDARY NCP METHOD TO ALLOCATE COSTS OF THE SECONDARY DISTRIBUTION SYSTEM?

A. Using only the sum of the individual customers' annual NCP to allocate secondary distribution costs would not recognize that there is some load diversity on the secondary system. On the other hand, using only the class NCP to allocate secondary costs would overstate the diversity.

To balance these considerations, the Company, consistent with CCOSSs from Prior Phase II Proceedings, allocated the capacity costs of the secondary distribution system to major customer classes taking service at secondary voltage using the Secondary NCP allocation factor. The derivation of this allocator is shown on Page 10 of Attachment DRB-2.

F. CCOSS Model

Q. PLEASE BRIEFLY DESCRIBE THE LAYOUT OF THE CCOSS IN ATTACHMENT DRB-2.

A. Table DRB-D-8 below contains a summary of how the Company's CCOSS presented in this proceeding is laid out:

Table DRB-D-8
Summary of CCOSS Presentation

Attachment DRB-1	Description
Page 1 through 2	• Table of Contents • Summary of the revenue requirements by specific cost function, as determined by the Final COS, as adjusted • Sets forth the revenue requirements factor for each function
Pages 3 through 6	• Summary of the customer sales and load data used to determine the specific demand and energy allocators
Pages 7 through 11	• Contain the derivation of the specific demand and energy allocators that are used to allocate the functional revenue requirements
Pages 12 through 22	• Contain the actual allocation of the individual functional revenue requirement amounts to the various major customer classes
Page 23	• Contains a summary of the allocated customer-related revenue requirements
Page 24	• Summary of allocated total revenue requirements that displays the revenue requirements separately by customer costs, system capacity costs, and energy costs • System capacity costs are broken down into five levels of production and delivery systems
Page 25	• Provides the allocation of DSM and EAP revenue requirements to each major customer class using a revenue allocation factor and shows the total revenue requirement for each rate class

Q. YOU INDICATE THAT THE SECOND PAGE OF ATTACHMENT DRB-2 CONTAINS A REVENUE REQUIREMENT FACTOR. WHAT IS A REVENUE REQUIREMENT FACTOR?

A. A revenue requirement factor is a calculation that represents the relationship between the revenue requirement and gross plant in service and/or the direct expense for each functional category in the CCOSS.

Q. HOW IS THE REVENUE REQUIREMENT FACTOR CALCULATED?

A. The revenue requirement factor is calculated by dividing the revenue requirement for each function by the basic plant investment and/or operating expense that underlies that specific function. For example, the "Metering" function represents the cost of owning and maintaining the Company's meters. The revenue requirement factor for the Metering function is determined by dividing the Metering function revenue requirement by the total original cost investment in metering equipment from Plant Account 370.

Likewise, the "Meter Reading" function represents the cost of reading meters for billing purposes. The revenue requirement factor for the Meter Reading function is determined by dividing the Meter Reading function revenue requirement by the total meter reading expense from Expense Account 902.

Q. WHY ARE THE REVENUE REQUIREMENT FACTORS IMPORTANT?

A. Revenue requirement factors are important because they are used in the class allocation process to determine the revenue requirements associated with plant and expense items that are allocated to a specific major customer class.

Q. HAS THERE BEEN ANY CHANGE IN THE COMPANY'S CCOSS MODEL FROM PRIOR PHASE II ELECTRIC RATE CASES?

A. Yes. The Company converted its class cost of service model from a Microsoft Excel® spreadsheet model to a new software system, the Regulatory Information System ("RIS"). The RIS system is developed by Utilities International. The RIS is an integrated system that calculates both revenue requirements (a cost of service study ("COS")) and the CCOSS.

Q. WHY DID THE COMPANY MAKE THIS TRANSITION TO A RIS CCOSS MODEL?

A. The Company is currently using RIS to develop its COS models, and RIS was used to develop the Final COS that is used as the basis for the Company's Phase I revenue requirement. Using the RIS model for the CCOSS in this case is the natural progression. In addition, RIS allows the Company to develop more detailed reports based on the data from both the COS and CCOSS in a much faster time frame.

Q. HAS THE COMPANY PROVIDED AN EXECUTABLE CCOSS MODEL AS PART OF THIS FILING?

A. Yes. The Company is providing an executable version of its CCOSS model in Excel® format, exported from RIS, that performs the class cost of service study calculations. This is the CCOSS that is provided as Attachment DRB-2.

Q. IS THE COMPANY PROVIDING ADDITIONAL INFORMATION TO ENSURE THE RIS CCOSS IS ACCURATE?

A. Yes. The Company will make the Microsoft Excel® spreadsheet CCOSS model based on the 2019 TY available to interested parties as part of discovery. This is the same format that has been filed in Prior Phase II Proceedings. Thus, interested parties will have the ability to compare the RIS CCOSS from this proceeding to the Company's prior spreadsheet-based CCOSS model to provide assurance that the RIS CCOSS model is accurate.

Q. ARE THERE ANY DIFFERENCES BETWEEN THE TWO CCOSS MODELS?

A. There are small rounding differences between the two models. The RIS version of the CCOSS utilizes more data records from the Final COS model than the Microsoft Excel spreadsheet CCOSS model. Table DRB-D-9 below compares major customer class cost responsibilities between the two models. As you can see, there are only small differences between major customer classes due to rounding.

Table DRB-D-9
Revenue Requirement Comparison RIS versus Excel CCOSS

Customer Class	Microsoft Excel CCOSS	RIS CCOSS	$ Difference from Excel Version	% Difference
Residential General	$ 806,593,036	$ 806,592,973	$ (63)	-0.00001%
Total Residential	$ 806,593,036	$ 806,592,973	$ (63)	-0.00001%
Small Commerical	$ 99,173,927	$ 99,173,921	$ (6)	-0.00001%
C&I Secondary	$ 675,412,416	$ 675,412,358	$ (58)	-0.00001%
C&I Primary	$ 150,455,014	$ 150,454,828	$ (186)	-0.00012%
C&I Transmission	$ 65,760,107	$ 65,760,102	$ (5)	-0.00001%
Total C&I	$ 891,627,537	$ 891,627,288	$ (249)	-0.00003%
Street and Area Lighting	$ 36,573,326	$ 36,573,325	$ (1)	0.00000%
Traffic Signal Lighting	$ 1,134,109	$ 1,134,431	$ 322	0.02839%
Total Lighting	$ 37,707,435	$ 37,707,756	$ 321	0.00085%
Interconnection Charges	$ 483,480	$ 483,480	$ -	
Rounding - Functional Allocations	$ 1		$ (1)	
Rounding - Class Allocations	$ 1		$ (1)	
CPUC Total	$ 1,835,585,417	$ 1,835,585,418	$ 1	0.00000%

Q. DO THESE ROUNDING DIFFERENCES SHOW UP IN THE CCOSS ALLOCATION FACTORS?

A. Yes. Since the two models utilize the same load research data, and the allocation factors are derived using the same allocation methodologies, therefore there is little to no difference in the allocation factors, as shown in Table DRB-D-10 below.

Table DRB-D-10
Allocation Factor Comparison RIS versus Excel CCOSS

4CP - AED - Allocation			
	CCOSS	RIS-CCOSS	Change
Residential	42.85508%	42.85508%	0.00000%
Small Commercial	5.06899%	5.06899%	0.00000%
C&I Secondary	37.99978%	37.99978%	0.00000%
C&I Primary	8.82184%	8.82183%	-0.00019%
C&I Transmission	4.87002%	4.87002%	0.00000%

NCP - Allocation			
	CCOSS	RIS-CCOSS	Change
Residential	45.75047%	45.75047%	0.00000%
Small Commercial	5.39862%	5.39862%	0.00000%
C&I Secondary	39.78719%	39.78719%	0.00000%
C&I Primary	8.39775%	8.39775%	0.00000%
C&I Transmission	- NA -	- NA -	- NA -

Secondary NCP - Allocation			
	CCOSS	RIS-CCOSS	Change
Residential	58.17127%	58.17127%	0.00000%
Small Commercial	5.54787%	5.54787%	0.00000%
C&I Secondary	35.76282%	35.76282%	0.00000%
C&I Primary	- NA -	- NA -	- NA -
C&I Transmission	- NA -	- NA -	- NA -

Energy - Allocation			
	CCOSS	RIS-CCOSS	Change
Residential	32.46472%	32.46472%	0.00000%
Small Commercial	4.55016%	4.55016%	0.00000%
C&I Secondary	41.92114%	41.92114%	0.00000%
C&I Primary	12.45264%	12.45264%	0.00000%
C&I Transmission	7.95300%	7.95300%	0.00000%

V. ANALYSIS OF CCOSS RESULTS

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

A. In this section, I discuss the primary drivers of the changes in class cost responsibilities between the 2016 Phase II Rate Case CCOSS and the CCOSS for this proceeding.

Q. PLEASE SUMMARIZE THE CHANGE IN CLASS COST RESPONSIBILITIES BETWEEN THE 2016 PHASE II RATE CASE AND THE CCOSS IN THIS PROCEEDING.

A. The Residential class's cost responsibility has increased since the 2016 Phase II rate case, the Small Commercial class's cost responsibility is virtually unchanged, and the other classes' cost responsibility has decreased. As discussed in more detail by Mr. Martinez, these changes primarily are a result of changes in underlying usage of the system by all classes. Changes in the relative mix of functionalized costs is a lesser contributing factor.

A. Functionalized Costs

Q. HOW HAVE THE FUNCTIONALIZED REVENUE REQUIREMENTS CHANGED SINCE THE COMPANY'S 2016 PHASE II RATE CASE?

A. Table DRB-D-11 summarizes the changes to functionalized revenue requirements since the Company's 2016 Phase II Rate Case. The increase in costs were discussed as part of the Company's 2019 Phase I Rate Case and are summarized in the Direct Testimony of Company witness Ms. Brooke A. Trammell in this instant proceeding.

Table DRB-D-11
Summary of Changes in Functionalized Revenue Requirements

Functionalized Costs	Allocation Methodology	Functionalized RR 2013 TY Phase II	Functionalized RR 2019 TY Phase II	$ Difference	% Difference	% of Total - Difference
G, T, and Dist. Substations	4CP-AED	$ 857,024,868	$ 961,587,545	$ 104,562,677	12%	37.7%
Primary Distribution	Class NCP	$ 264,443,948	$ 328,385,514	$ 63,941,566	24%	23.0%
Production Energy	Energy	$ 129,429,170	$ 222,012,383	$ 92,583,214	72%	33.4%
Customer Related Costs	Weighted Customer Count	$ 105,847,173	$ 105,266,885	$ (580,288)	-1%	-0.2%
Secondary Distribution	Secondary NCP	$ 79,785,800	$ 94,283,439	$ 14,497,639	18%	5.2%
DSM & EAP	Revenue	$ 93,641,995	$ 96,159,533	$ 2,517,539	3%	0.9%

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

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.

B. Allocation Factors

Q. IN GENERAL, WHY WOULD CLASS ALLOCATION FACTORS CHANGE FROM ONE PHASE II TO THE NEXT?

A. Class allocation factors can change from one case to another due to changes in methodology for calculating the allocation factors or changes in underlying data.

As discussed above, the Company has not changed the methodology for calculating any of its allocation factors from what was used in Prior Phase II Proceedings. The changes in each class's relative share of the allocation factors in this Phase II Rate Case are entirely due to changes in the underlying data.

Q. HAVE THERE BEEN SIGNIFICANT CHANGES IN THE UNDERLYING USAGE CHARACTERISTICS OF THE DIFFERENT CUSTOMER CLASSES SINCE THE COMPANY'S 2016 PHASE II RATE CASE?

A. Yes. Mr. Martinez discusses the underlying changes to the usage patterns of the customer classes in his Direct Testimony.

Q. DO THOSE CHANGES IMPACT CLASS COST RESPONSIBILITIES?

A. Yes. The underlying changes in usage patterns show up in the data that is used to calculate the different allocation factors that ultimately allocate costs to classes. The Company has prepared the allocation factors using the same methodologies as were used in Prior Phase II Proceedings, but changes to the underlying data result in changes to each class's relative share of each allocation factor.

Q. WHY SHOULD CLASSES' SHARE OF ALLOCATION FACTORS CHANGE WHEN THE UNDERLYING DATA CHANGES?

A. The underlying data reflects how customers use the system, which can change over time. The 2016 Phase II Rate Case was based on a test year ended December 31, 2013, and as discussed by Mr. Martinez in his Direct Testimony, customers' use of the system changed significantly in the intervening six years. Carrying those changes through to the allocation factors reflects the overall change in how the electrical system was used between wholesale and retail customers and among customer classes during the respective test years. That usage ultimately drives cost and therefore must be captured in the CCOSS.

Q. HOW HAVE EACH CLASS'S SHARE OF THE DIFFERENT ALLOCATION FACTORS CHANGED SINCE THE COMPANY'S 2016 PHASE II RATE CASE?

A. Table DRB-D-12 compares each class's share of the 4CP-AED, Class Annual NCP, Secondary NCP, and energy allocation factors in the 2016 Phase II Rate Case and this Phase II Rate Case.

Table DRB-D-12
Comparison of Allocation Factors

4CP - AED - Allocation			
	2013 TY Phase II	2019 TY Phase II	Change
Residential	38%	43%	13%
Small Commercial	5%	5%	-1%
C&I Secondary	42%	38%	-10%
C&I Primary	9%	9%	2%
C&I Transmission	6%	5%	-16%

NCP - Allocation			
	2013 TY Phase II	2019 TY Phase II	Change
Residential	42%	46%	8%
Small Commercial	6%	5%	-9%
C&I Secondary	43%	40%	-7%
C&I Primary	8%	8%	2%
C&I Transmission	- NA -	- NA -	- NA -

Secondary NCP - Allocation			
	2013 TY Phase II	2019 TY Phase II	Change
Residential	57%	58%	2%
Small Commercial	6%	6%	-8%
C&I Secondary	36%	36%	-1%
C&I Primary	- NA -	- NA -	- NA -
C&I Transmission	- NA -	- NA -	- NA -

Energy - Allocation			
	2013 TY Phase II	2019 TY Phase II	Change
Residential	31.6%	32.5%	2.6%
Small Commercial	4.7%	4.6%	-3.3%
C&I Secondary	42.0%	41.9%	-0.2%
C&I Primary	12.0%	12.5%	3.5%
C&I Transmission	8.9%	8.0%	-10.6%

Q. CAN YOU EXPLAIN WHY THE RESIDENTIAL CLASS HAS SEEN AN INCREASE IN ALL ALLOCATORS SINCE THE LAST RATE CASE?

A. The Company has added approximately 90,000 Residential customers between the 2016 Phase II Rate Case (based on a 2013 Test Year) and this Phase II Rate Case (based on a test year ended August 31, 2019). This absolute growth makes the Residential class a larger portion of our system. Further, as discussed in more detail by Mr. Martinez in his Direct Testimony, there have been relative changes in the usage characteristics among the classes, with the Residential class accounting for a larger share of usage during system peak hours.

Table DRB-D-13 below identifies changes to the underlying data for the Residential class that is used to calculate various allocation factors. The significant growth in customers, energy and demands drives the increase in the Residential class's relative share of the CCOSS allocation factors. Further, as shown in the tables below, not only has the Residential class experienced absolute growth in the underlying components of each allocation factor, its relative share of total customers, energy and demands has increased, which further increases the Residential class's relative share of the CCOSS allocation factors.

Table DRB-D-13
Summary of Residential Changes

Residential

	2016 Phase II (2013 Test Year)	2020 Phase II (2019 Test Year)	Change	
Customers	1,177,754	1,271,522	93,768	8.0%
Annual Energy	8,880,334,514 kWh	9,371,786,280 kWh	491,451,766 kWh	5.5%
Non Coincident Peak (NCP)	2,539,849 kW	2,932,327 kW	392,478 kW	15.5%
4 Summer Coincident Peak (4CP)	1,820,691 kW	2,202,046 kW	381,355 kW	20.9%
Ave. Energy Per Customer	628 kWh	614 kWh	-14 kWh	-2.2%
Average NCP	2.2 kW	2.3 kW	0.1 kW	6.9%
Average 4CP	1.55 kW	1.73 kW	0.2 kW	12.0%
NCP Load Factor	39.9%	36.5%	-3.4%	-8.6%
4CP Load Factor	55.7%	48.6%	-7.1%	-12.7%

Q. PLEASE DISCUSS THE CHANGES IN C&I SECONDARY CLASS ALLOCATORS.

A. As discussed by Mr. Martinez in his Direct Testimony, the C&I Secondary customer class has become more energy efficient, reducing their kWh use per customer by about five percent, and also decreasing their kW use per customer during summer peak times by about nine percent. Table DRB-D-14 below shows changes in the underlying data for the C&I Secondary class that is used to calculate the various allocation factors in the CCOSS. The C&I Secondary class's relative share of each of the major allocation factors is lower than in the 2016 Phase II Rate Case. As with the Residential class, this change is due to absolute and relative changes in customers, energy, and demands.

Table DRB-D-14
Summary of C&I Secondary Changes

C&I Secondary

	2016 Phase II (2013 Test Year)	2020 Phase II (2019 Test Year)	Change	
Customers	39,558	42,540	2,982	7.5%
Annual Energy	11,797,929,988 kWh	12,101,625,363 kWh	303,695,375 kWh	2.6%
Non Coincident Peak (NCP)	2,560,991 kW	2,550,117 kW	-10,874 kW	-0.4%
4 Summer Coincident Peak (4CP)	2,051,897 kW	2,013,649 kW	-38,248 kW	-1.9%
Ave. Use Per Customer	24,854 kWh	23,706 kWh	-1,147 kWh	-4.6%
Average NCP	64.7 kW	59.9 kW	-4.8 kW	-7.4%
Average 4CP	51.9 kW	47.3 kW	-4.5 kW	-8.7%
NCP Load Factor	52.6%	54.2%	1.6%	3.0%
4CP Load Factor	65.6%	68.6%	3.0%	4.5%

Q. PLEASE EXPLAIN THE CHANGES IN C&I TRANSMISSION CLASS ALLOCATORS.

A. The Company has added a few C&I Transmission customers since its last rate case. Many C&I Transmission customers have become more energy efficient, reducing their kWh use per customer by about 25 percent. As a class, they have also reduced their kW use during summer peak times by about 26 percent. Mr. Martinez discusses these trends and changes in more detail in his Direct Testimony.

Table DRB-D-15 below shows changes in the underlying data for the C&I Transmission class that is used to calculate the various allocation factors in the CCOSS. The C&I Transmission class's relative share of each of the major allocation factors is lower than the 2016 Phase II Rate Case. As with the Residential and C&I Secondary classes, this change is due to absolute and relative changes in customers, energy, and demands.

Table DRB-D-15
Summary of C&I Transmission Changes

C&I Transmission

	2016 Phase II (2013 Test Year)	2020 Phase II (2019 Test Year)	Change	
Customers	30	37	7	23.3%
Annual Energy	2,612,222,396 kWh	2,401,449,139 kWh	-210,773,257 kWh	-8.1%
4 Summer Coincident Peak (4CP)	317,857 kW	288,379 kW	-29,478 kW	-9.3%
Ave. Use Per Customer	7,256,173 kWh	5,408,669 kWh	-1,847,504 kWh	-25.5%
Average 4CP	10,595.2 kW	7,794.0 kW	-2,801.2 kW	-26.4%
4CP Load Factor	93.8%	95.1%	1.2%	1.3%

Q. DO RELATIVE CHANGES IN CONTRIBUTION TO PEAK DEMANDS HAVE AN OUTSIZED EFFECT ON CLASS COST RESPONSIBILITY?

A. Yes. As shown in Table DRB-D-16 below, approximately 75 percent of the Company's total revenue requirement is allocated using allocation factors (4CP-AED, Class Annual NCP, or Secondary NCP) that rely in whole or part on peak demands. Therefore, if a class's demand increases while other classes' demands decrease, it will have an outsized effect on the class's total allocated revenue requirement. In addition, if functionalized revenue requirements are increasing in categories allocated based on the 4CP-AED, Class Annual NCP or Secondary NCP allocation factors, customer classes will see a larger allocation of those revenue requirements. The revenue requirements by allocation methodology are outlined in table DRB-D-16 below.

Table DRB-D-16
Revenue Requirements by Allocation Methodology

Functionalized Costs	Allocation Methodology	Functionalized RR 2019 TY Phase II	% of Total
G, T, and Distributon Substations	4CP-AED	$ 961,587,545	52%
Primary Distribution	Class NCP	$ 328,385,514	18%
Production Energy	Energy	$ 222,012,383	12%
Customer Related Costs	Weighted Customer Count	$ 105,266,885	6%
Secondary Distribution	Secondary NCP	$ 94,283,439	5%
DSM & EAP	Revenue	$ 96,159,533	5%
	subtotal	$ 1,807,695,300	98%
	Direct Assignment - Lighting	$ 27,890,118	2%
	TOTAL Revenue Requirement	$ 1,835,585,417	100%

VI. CCOSS STAKEHOLDER MEETINGS

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

A. In this section, I detail the Company's compliance with the relevant CCOSS stakeholder meeting requirements stemming from its 2016 Phase II Rate Case.

Q. PLEASE DISCUSS THE CCOSS STAKEHOLDER MEETINGS REQUIRED BY THE THREE CASE SETTLEMENT.

A. As set forth in more detail in the Three Case Settlement approved as part of the Company's 2016 Phase II Rate Case, the Company agreed to the following:

- Convene an informal collaborative group to discuss alternative methodologies for the classification and allocation of production plant, with a corresponding obligation to provide a summary of the group's discussions and conclusions, if any, in this proceeding; and
- Engage with interested stakeholders, including Staff and the industrial intervenors, to discuss possible long-term solutions for Transmission General customers who have specifically assigned substation facilities and experience a permanent load reduction, with a requirement to incorporate any agreed-upon solutions in the CCOSS presented in this case.

I defined these meetings as the "CCOSS Stakeholder Meetings" earlier in my Direct Testimony.

Q. PLEASE SUMMARIZE THE CCOSS STAKEHOLDER MEETINGS PUBLIC SERVICE HAS CONDUCTED, ALONG WITH THE RELEVANT OUTCOMES.

A. The Company held two CCOSS Stakeholder meetings, one on August 30, 2017 and the other on February 22, 2018. A SharePoint site was set up, and participants had access to the site to review notes and access information. Participants were invited to edit notes and provide feedback after notes were completed and posted to the site by the Company.

A number of stakeholders were present at the August 30, 2017 meeting. In addition to the Company, representatives of the following were in attendance: Energy Outreach Colorado, the Office of Consumer Counsel ("OCC"), Colorado Energy Consumers ("CEC"), Colorado Energy Office, Climax Molybdenum Company ("Climax"), Western Resource Advocates, and Walmart Stores, Inc. and Sam's West, Inc. ("Walmart"). Discussions at the meeting included:

- Goals of the CCOSS stakeholder group;
- Review of the current 4CP-AED methodology;
- Classification of production plant as either energy-related or capacity-related (this is known as stratification);
- Allocation of stratified energy costs using the E8760[12] allocator;
- An overview of alternative cost allocation methodologies, including 1CP, 4CP, 12CP, marginal cost, base intermediate peaker, and others; and
- An overview of transmission general service and facility charges and how those charges are derived.

At the conclusion of the meeting, stakeholders discussed next steps. The parties determined that an additional meeting was appropriate to discuss the

[12] The E8760 energy allocator is used to allocate the energy-related portion of production costs, it is calculated by weighting each class's load for each of the 8,760 hours of a test year by the corresponding hourly marginal energy cost. Each class's weighted marginal cost is then divided by the weighted total of all classes to determine the allocation percentage by class.

differences between a future CCOSS and stratified CCOSS based on 2017 rate case assumptions, the impact of wind projects, and AGIS in a future CCOSS.

As mentioned above, the next meeting was held on February 22, 2018. Representatives from the Company, OCC, CEC, Climax, Vote Solar, and Walmart were in attendance, in addition to independent advocate Karey Christ-Janer. Topics discussed included:

- Comparison between a CCOSS and stratified CCOSS based on data from the 2017 rate case;
- Impacts of Rush Creek revenue requirements in the ECA as compared to a Phase I electric rate case and Phase II electric rate case;
- Impacts of AGIS revenue requirements in a Phase I GRSA as compared to a Phase II electric rate case setting new base rates; and
- Impacts of Cherokee Combined Cycle in a Phase I GRSA as compared to a Phase II electric rate case setting new base rates.

The participants also discussed the Black Hills Energy minimum intercept method, thoughts on filing a Phase I and Phase II combined rate case, and next steps.

The Company offered to facilitate additional meetings if desired by the group, however, there was no request by any party for an additional meeting.

While the CCOSS Stakeholder Meetings were well attended, no group conclusions were reached, and there were no agreed-upon changes to be incorporated in this filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Dolores R. Basquez

I hold a Bachelor of Science Degree in Business Administration from Metropolitan State University of Denver. I began my career at Public Service Company of Colorado in 2001. I have held various regulatory positions, where I was responsible for managing all aspects of a regulatory case including the coordination and preparation of applications, advice letters, regulatory testimony, exhibits, discovery, and reports for filing with regulatory agencies. From 2008 to the present, I have held various Pricing Analyst positions with increasing responsibility for retail and wholesale pricing issues. As an Analyst I was responsible for cost allocation and rate design, developing the Company's cost adjustment filings, completion of financial and rate related analyses for the Company's electric, gas and steam operations. In January 2015 I assumed my current position of Pricing Consultant. In this role my primary responsibility is developing cost allocation studies and rate design for retail rate cases.

During my tenure with Public Service Company of Colorado, I have testified on issues related to the Company's Electric Commodity Adjustment and the development of buyback rates for Qualifying Facilities.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE NO. 1835-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO ELIMINATE THE CURRENTLY EFFECTIVE GENERAL RATE SCHEDULE ADJUSTMENTS TO PLACE INTO EFFECT REVISED BASE RATES AND OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE NOVEMBER 19, 2020	) PROCEEDING NO. 20AL-______E

AFFIDAVIT OF DOLORES R. BASQUEZ
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Dolores R. Basquez, 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 14th day of October, 2020.

DRB

Dolores R. Basquez
Pricing Consultant

Subscribed and sworn to before me this 14th day of October, 2020.

SCHUNA D WRIGHT
Notary Public
State of Colorado
Notary ID # 19974007693
My Commission Expires 05-06-2021

Schuna D. Wright
Notary Public

My Commission expires May 6, 2021