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

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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**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 15, 2023

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

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DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART

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DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven W. Wishart. My business address is 1800 Larimer, Suite 1100, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. (“XES”) as Director of Pricing and Regulatory Analytics. XES is a wholly owned subsidiary of Xcel Energy Inc. (“Xcel Energy”) and provides an array of support services to Public Service Company of Colorado (“Public Service” or the “Company”) and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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 the Director of Pricing and Regulatory Analytics, I am responsible for financial and policy analyses associated with the Company's electric, natural gas, and steam rates, in addition to the regular administration of the Company's electric, natural gas, and steam tariffs. My duties include providing quantitative analyses, cost allocation and rate design, and policy support on various state regulatory issues. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I address three aspects of the Company's rate design proposals in this proceeding: (1) allocation of production, transmission, and distribution substation costs to customer classes using a new Probability of Dispatch – Peak Hours ("POD-PH") methodology; (2) the role of demand charges in the Company's rate design; and (3) the demand threshold for the Small Commercial class. I also provide an analysis of the marginal cost to serve Economic Development Rate ("EDR") customers. Finally, I sponsor the calculation of the bill impacts of the Company's proposals in this case, including presentation of certain affordability metrics discussed in my Supplemental Direct Testimony in Proceeding No. 22AL-0530E (the "2022 Phase I").

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

A. Yes. I am sponsoring the following attachments that were created by me or under my direct supervision:

- Attachment SWW-1 – Colorado Public Utilities Commission Study: Impacts of Rate Design on Electrification Economics;
- Attachment SWW-2 – Economic Development Rate Marginal Cost Analysis; and
- Attachment SWW-3 – Bill Impact Analysis.

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

A. I recommend the Commission approve the use of the new POD-PH allocation methodology in the Company's Class Cost of Service Study ("CCOSS") and the modification of existing Commercial and Industrial ("C&I") Secondary Generation and Transmission ("G&T") demand charges to be time differentiated. I also recommend that the Commission maintain the demand threshold for the Small Commercial class at 50 kilowatts ("kW") and current Economic Development Rate discounts in Schedule EDR.

II. PRODUCTION, TRANSMISSION, AND DISTRIBUTION SUBSTATION COST ALLOCATION

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

A. The purpose of this section of my Direct Testimony is to support the Company's proposed class cost allocation methodology for production, transmission, and distribution substation costs. Company witness Mr. Derek S. Klingeman sponsors the actual class costs allocation analysis and the CCOSS; I support the Company's reasoning behind our proposed methodology.

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS PROCEEDING REGARDING CLASS COST ALLOCATION OF PRODUCTION, TRANSMISSION, AND DISTRIBUTION SUBSTATION COSTS?

A. The Company is proposing to implement a new allocation methodology in this proceeding, the POD-PH methodology. This method allocates costs based on which generating units are expected to be running during the top 1,000 load hours of the year, the base rate costs of those units, and each customer class's share of load in each of those hours. Mr. Klingeman provides a more detailed explanation of the POD-PH calculations and a supporting attachment as part of his Direct Testimony.

Q. HOW DID PUBLIC SERVICE PREVIOUSLY ALLOCATE PRODUCTION, TRANSMISSION, AND DISTRIBUTION SUBSTATION COSTS?

A. For many years, the Company allocated most production, transmission, and distribution substation costs across customer classes based on the four coincident-peak ("4CP") average and excess demand ("AED") methodology ("4CP-AED") methodology. Wind resources in base rates and production energy cost (*i.e.*, variable operations and maintenance ("O&M") costs) were previously allocated using a simple annual energy allocation method.

Q. DID THE COMMISSION ORDER THE COMPANY TO ASSESS ALLOCATION OF PRODUCTION COSTS IN THIS PROCEEDING?

A. Yes. Decision No. C21-0536 (the "2020 Phase II Decision") in Proceeding No. 20AL-0432E (the "2020 Phase II") included direction to "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."[1]

Q. WHY IS THE COMPANY SUPPORTING THE POD-PH COST ALLOCATION METHODOLOGY IN THIS PROCEEDING?

A. We find that the POD-PH method supports our principle of fairness, as it allocates the cost of resources based on class usage during each of the top 1,000 hours. Conversely, the 4CP-AED method places a very large weight on just four hours of the year. The POD-PH method also is attractive because it can be consistently applied across all generation assets that are currently in rate base and those that may be added in the future.

The POD-PH methodology also supports our principle of stability. As discussed above, the 4CP-AED allocation methodology was heavily influenced by

[1] Proceeding No. 20AL-0432E, Decision No. C21-0536, p. 20, ¶ 47.

the coincident peak demand hour during the four summer months. Changes in the timing of those hours have significantly altered class cost responsibilities. For example, in the 2020 Phase II, the coincident peak hour shifted from 3:00 PM to 4:00 PM, which drove an approximate $30 million increase to Residential cost responsibility.[2] By incorporating the top 1,000 load hours, the POD-PH methodology naturally moderates the importance of any particular hour.

Finally, the POD-PH methodology will evolve naturally as the customer load and dispatch of our system changes. With electrification of heating load, it is likely that in the future Public Service will switch from a summer peaking electric system to a winter peaking electric system sometime in the future. The POD-PH methodology accounts for the top 1,000 load hours regardless of which season or hour they occur and will not need to be changed as our system evolves. And by focusing on a larger number of hours, the POD-PH methodology will incorporate these changes gradually rather than all at once, as would occur under the 4CP-AED methodology.

Q. IF THE POD-PH METHOD IS BASED ON DISPATCH OF PRODUCTION RESOURCES, WHY IS IT ALSO APPLIED TO TRANSMISSION AND DISTRIBUTION SUBSTATION COSTS?

A. Public Service has traditionally used the same allocation method for transmission and distribution substation costs as it has for production. The reasoning is that transmission and substations exist to deliver the energy produced by generation

[2] Proceeding No. 20AL-0432E, Hrg. Ex. 101 at 45:10-17, 46:7-11 (Trammell Direct).

assets and therefore should be allocated in the same manner. We are recommending this practice continue in this proceeding.

Q. HOW DOES CLASS COST RESPONSIBILITY UNDER THE POD-PH METHODOLOGY COMPARE TO THE 4CP-AED METHODOLOGY?

A. Allocating production, transmission, and distribution substation costs based on the POD-PH method results in lower cost allocation for Residential, Small Commercial, and Street Lighting classes as compared to allocation using the 4CP-AED method.[3] The other classes will have higher cost allocations when using POD-PH, with the largest increase in the C&I Transmission class. These relationships are shown in the table below.

Table SWW-D-1
Comparison of Class Cost Responsibility Under Different Production, Transmission, and Distribution Substation Allocation Methodologies

	4CP-AED 2016 Phase II	4CP-AED 2020 Phase II	4CP-AED 2023 Phase II	POD-PH 2023 Phase II
Residential	38.0%	42.9%	46.1%	41.2%
Small Commercial	5.1%	5.1%	4.8%	4.5%
C&I Secondary	42.1%	38.0%	36.1%	37.8%
C&I Primary	8.5%	8.8%	8.0%	10.0%
C&I Transmission	5.8%	4.9%	4.7%	6.2%
Street Lighting	0.38%	0.34%	0.27%	0.17%
Traffic Lighting	0.06%	0.05%	0.04%	0.06%

[3] As discussed by Mr. Klingeman, the Company's major CCOSS classes are: Residential, Small Commercial, C&I Secondary, C&I Primary, C&I Transmission, Street and Area Lighting and Traffic Signal Lighting.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS BASED ON THE INFORMATION IN TABLE SWW-D-1?

A. Yes. Table SWW-D-1 illustrates that using the 4CP-AED methodology would have resulted in another increase in Residential class cost responsibility on the heels of the increase in the 2020 Phase II. Second, the class cost responsibilities using POD-PH generally are consistent with those from the 2020 Phase II and Proceeding No. 16AL-0048E (the "2016 Phase II"). Finally, I believe that the resulting class cost responsibilities are reasonable in the context of the 2020 Phase II and 2016 Phase II cases. In the 2020 Phase II, the Residential class saw a large increase in its cost responsibility due to the 4CP-AED allocation method and the C&I Transmission class saw a large decrease. In the context of those cases and the resulting rate impacts, I believe that moving to the POD-PH methodology results in a reasonable allocation among customer classes.

III. C&I SECONDARY DEMAND CHARGES

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

A. In this section of my testimony, I discuss the topic of demand charges in rates for C&I Secondary customers and their use by Public Service in C&I Secondary rate design. In doing, so I respond to the Commission's request in the 2020 Phase II Decision that the Company provide an analysis of C&I Secondary demand charges in this proceeding. I also discuss and support the Company's proposal to introduce time differentiated G&T demand charges to C&I Secondary rate schedules in this proceeding.

A. Role and Use of Demand Charges in C&I Secondary Rate Design

Q. PLEASE DESCRIBE THE COMMISSION'S REQUEST IN THE 2020 PHASE II DECISION THAT THE COMPANY PROVIDE AN ANALYSIS OF C&I SECONDARY DEMAND CHARGES.

A. The 2020 Phase II Decision directed that the Company address the following as it relates to C&I Secondary rates:[4]

> the relationship of non-coincident demand charges to cost causation, and how the Commission should view rates that rely heavily on the demand component for recovery in light of: (a) the broad move to time differentiated rates for other major rate classes in an effort to send more accurate price signals; and (b) the potential risk that the current design may be at odds with state policy goals related to both solar adoption, as well as electrification of smaller commercial facilities.

[4] Proceeding No. 20AL-0432E, Decision No. C21-0536, p. 9, ¶ 21.

Q. WHAT ARE DEMAND CHARGES?

A. Demand charges are charges that are based on the maximum amount of electricity used during a particular period of time. For the Company, demands are measured over 15-minute intervals.[5] Demand charges differ from energy charges, which are based on the total amount of electricity used over a particular period.

Q. DOES THE COMPANY'S MAIN C&I SECONDARY RATE INCLUDE DIFFERENT KINDS OF DEMAND CHARGES?

A. Yes. Schedule SG is the main rate schedule for C&I Secondary customers and it includes two kinds of demand charges: (1) a distribution demand charge; and (2) G&T demand charge. The distribution demand charge recovers the cost of distribution systems. The G&T demand charge is intended to recover production and transmission costs.

Q. DO NON-COINCIDENT DEMAND CHARGES REFLECT COST CAUSATION FOR THE PRIMARY AND SECONDARY DISTRIBUTION SYSTEMS?

A. Yes. Non-coincident demand charges do a good job of reflecting cost causation within the distribution system, particularly the smaller, more localized secondary distribution system.

Q. WHY DO NON-COINCIDENT DEMAND CHARGES DO A GOOD JOB OF REFLECTING COST CAUSATION FOR DISTRIBUTION SYSTEMS?

A. Mr. Klingeman explains that load diversity decreases as you move deeper into the electric system, meaning the individualized usage of customers has a larger impact

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[5] *See* Colo. PUC No. 8 Electric Tariff ("Electric Tariff" or "Tariff") at Sheet Nos. 18 (definition of Billing Demand), 19 (definition of Demand), and 20 (definition of Measured Demand).

on system costs the closer you get to the point of delivery. This is because all components must be designed to accommodate the expected maximum load at that particular point on the system, regardless of when that maximum occurs. Non-coincident demand charges, which consider each customer's maximum 15-minute usage at any time during a month, are therefore particularly well matched to cost causation as you get beyond distribution substations and deeper into the distribution system.

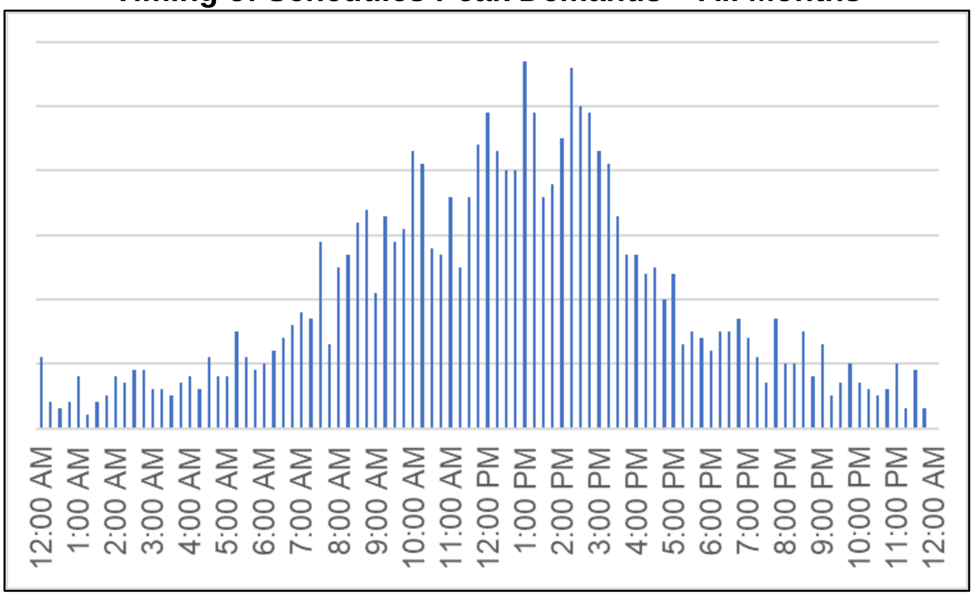
Q. DO NON-COINCIDENT DEMAND CHARGES DO A PARTICULARLY GOOD JOB OF REFLECTING COST CAUSATION AS YOU MOVE TO HIGHER LEVELS OF THE ELECTRIC SYSTEM?

A. Not necessarily. Again, as you move to higher levels of the electric system, diversity increases, meaning the maximum usage of any particular customer has less of an effect on the total sizing or need at that particular level. There is relatively more load diversity at the generation and transmission level, making system peaks (for which capacity at those levels is developed) more important for cost causation than non-coincident (individualized) demands. This is the main reason the Company is recommending a transition to time differentiated G&T demand charges for C&I Secondary customers, as discussed below.

Q. CAN YOU DEMONSTRATE HOW THE NON-COINCIDENT PEAKS DO NOT NECESSARILY LINE UP WITH SYSTEM PEAKS THAT CONTRIBUTE TO GENERATION, TRANSMISSION, AND DISTRIBUTION SUBSTATION COSTS?

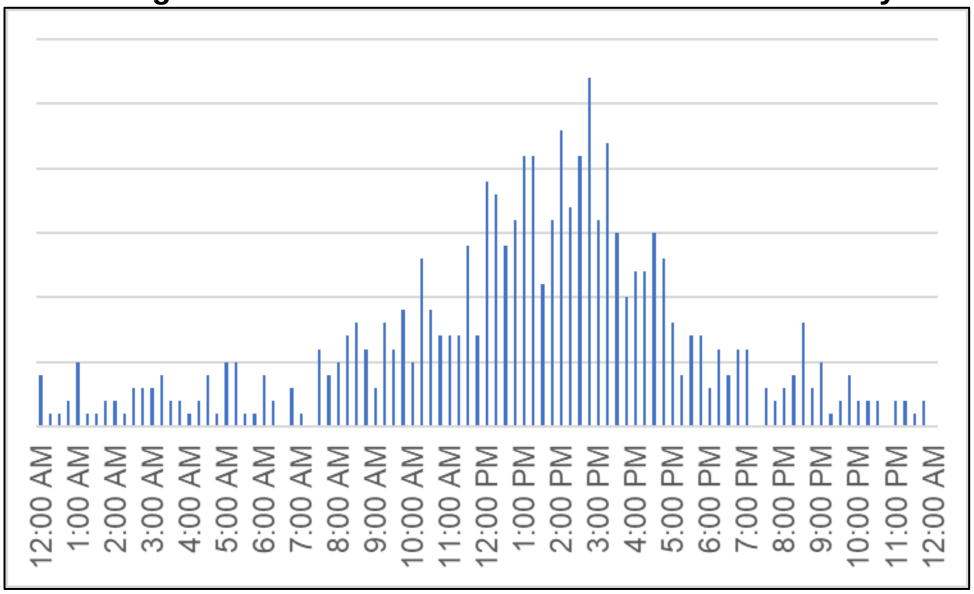
A. Yes. I analyzed 2022 load research data of 159 randomly selected Schedule SG customers. For each customer and each month, I identified the 15-minute interval in which the customer's energy use was highest. The result showed a fairly wide distribution for the timing of peak demands, with at least one observation in each 15-minute interval of the day. The most common time was 1:00 PM. The following figure illustrates the distribution of the timing of peak demands.

Figure SWW-D-1
Timing of Schedules Peak Demands – All Months



The distribution of peaks was somewhat more concentrated in the summer months and shifted later in the day, with the most common peak demand time being 2:45 PM.

Figure SWW-D-2
Timing of Schedule SG Peak Demands – Summer Only



Ultimately, non-coincident G&T demand charges may be assessing costs based on usage occurring well outside of the most important hours, which, as shown the time of use ("TOU") analysis of Company witness Mr. Jeffrey R. Knighten, primarily occur in the existing peak period of 3:00 PM to 7:00 PM. The Company seeks to improve this situation by introducing time differentiated demand charges to its main C&I Secondary rate schedules, as discussed below.

Q. DO TOU ENERGY CHARGES DO A BETTER JOB OF REFLECTING COST CAUSATION FOR GENERATION AND TRANSMISSION?

A. I do not believe so. No rate design is perfect and TOU energy charges can have the same flaws as non-coincident demand charges in that they may apply at a time that is unimportant from a cost causation perspective.

Q. HOW DID YOU CONCLUDE THAT TOU ENERGY CHARGES CAN APPLY DURING UNIMPORTANT HOURS?

A. I analyzed 2022 load data to assess the timing of load net of renewable generation during the existing TOU on-peak period of 3:00 PM to 7:00 PM. I found that even though 3:00 PM to 7:00 PM was likely the most appropriate on-peak period, the correlation with actual load net of renewable generation was low. Of our top 100 load net of renewable generation hours, only 71 occurred during on-peak periods and 15 of the lowest 100 load net of renewable hours occurred during on-peak periods.

Table SWW-D-2
Correlation of Load Net of Renewable Generation & On-Peak Periods

Load Net Renewables	Number of On-Peak Hours
Top 100 Hours	71
Top 500 Hours	239
Top 1,000 Hours	396
Bottom 1,000 Hours	136
Bottom 500 Hours	81
Bottom 100 Hours	15

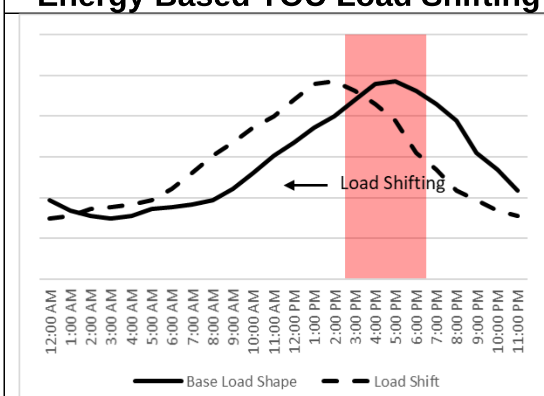
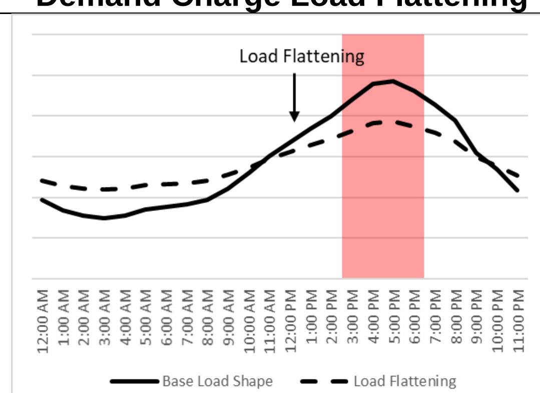
Q. DO THE RESULTS OF YOUR ANALYSIS MEAN TOU PERIODS SHOULD BE ADJUSTED IN THIS PROCEEDING?

A. No. Mr. Knighten provides a more detailed analysis and assessment of TOU periods in his Direct Testimony and presents the Company's reasoning for maintaining the TOU periods for affected rate schedules. I presented this analysis to emphasize that any static rate design with static pricing (whether TOU energy, non-coincident demand or time differentiated demand) will result in some disconnect between pricing and cost causation.

Q. DO TOU ENERGY CHARGES SEND A BETTER PRICE SIGNAL THAN DEMAND CHARGES?

A. No, I do not believe that an energy-based TOU pricing structure sends a better price signal. My perspective is that TOU energy charges encourage customers to shift the timing of their usage, while demand charges encourage customers to flatten their load profile. Both types of changes can be beneficial to the electric grid, but load flattening can both reduce coincident peak demand, which contributes to generation and transmission, and non-coincident peak demand which contributes to distribution costs. On the other hand, simply shifting the timing of peak usage through energy-based TOU rates will not minimize future investment in the local distribution system.

Figures SWW-D-3 and SWW-D-4:
Load Shifting and Flattening

Figure SWW-D-3 **Energy Based TOU Load Shifting**	**Figure SWW-D-4** **Demand Charge Load Flattening**
	

Q. IS THE CURRENT C&I SECONDARY RATE DESIGN AT ODDS WITH STATE POLICY REGARDING SOLAR ADOPTION?

A. No. Schedule SG incentivizes businesses to use electricity in a smooth and steady fashion. Such high load factor load profiles are beneficial to our system in that they tend to have more energy use in the off-peak periods when renewable energy is more likely to be prevalent. Further, the Company has a specific rate option (Schedule SPVTOU-B) for C&I Secondary customers that are interested in installing net metered solar. I recently calculated that the average net metering credit under Schedule SPVTOU-B was about $95/MWh. SPVTOU-B does have a minimum load factor requirement, but based on 2022 billing data, I estimate that approximately 79 percent of C&I Secondary customers and 95 percent of SG load would meet that requirement. I note that between rate options available for Residential and Small Commercial customers and Schedule SPVTOU-B (available to approximately 79 percent of C&I Secondary customers) about 99 percent of customers or 77 percent of load have a favorable rate option for net metering.

Q. IS THE CURRENT C&I SECONDARY RATE DESIGN AT ODDS WITH STATE POLICY REGARDING ELECTRIFICATION?

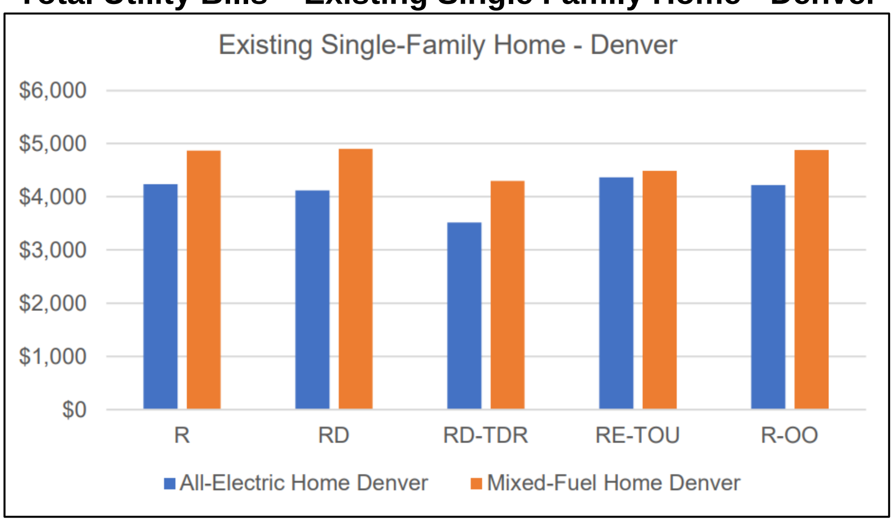
A. Demand charges were a barrier to some electric vehicle ("EV") charging applications due to the low load factors associated with fast charging facilities. However, that issue has been substantially addressed through Schedules S-EV and S-EV-CPP. And as discussed more by company witness Mr. Knighten, the Company is proposing to create similar rate options for C&I Primary customers through new Schedules P-EV and P-EV-CPP. As a result, I do not view the current

C&I Secondary rate design as being at odds with state policy regarding transportation electrification.

Nor do I view demand charges as being a barrier to building electrification. Although it is not my area of expertise, my understanding is that heat pumps run consistently during periods of cold weather and do not demonstrate dramatic spikes in load. With high load factor operation like that, heat pumps should be relatively inexpensive to run under a demand charge-based rate schedule.

The Commission's Impact of Rate Design on Electrification Economics report supports this conclusion.[6] The report contains several figures illustrating total utility bills for mixed fuel buildings and all electric buildings. For single family, all electric homes, demand-based rate schedules such as former Schedule RD-TDR have a clear advantage over kWh-based rate schedules, as the following figure illustrates.

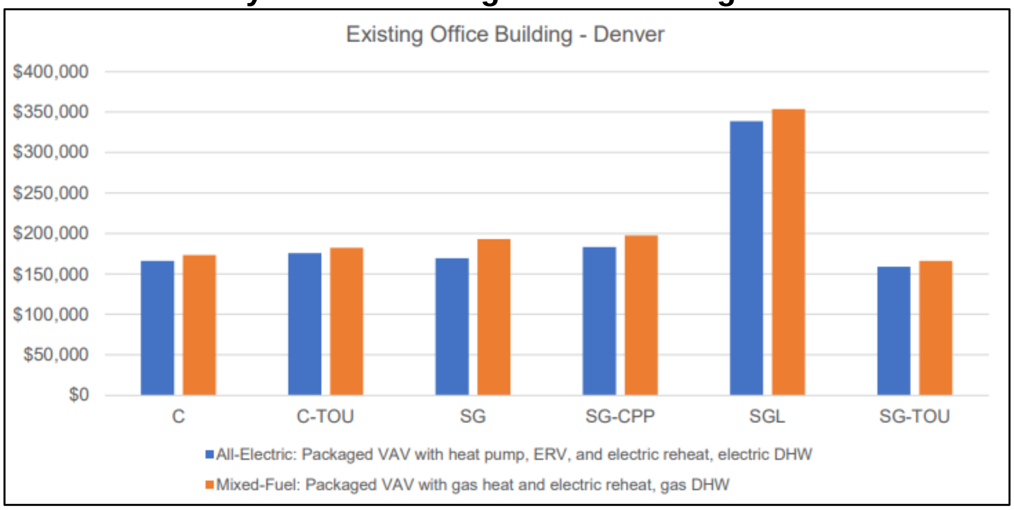
Figure SWW-D-5
Total Utility Bills – Existing Single Family Home - Denver



[6] A copy of this report is included as Attachment SWW-1. It also is publicly available at https://drive.google.com/file/d/10iSZRoJIZgZ3E_12FOSbUsN95OUtRt6D/view.

The report's findings are not as conclusive for commercial buildings, but there also is no indication that rates with demand charges (like Schedule SG) are burdensome in any way. The following figure, also from the Commission's report, shows that total utility bills for an all-electric office building are very similar under Schedules SG and SG-TOU.

Figure SWW-D-6
Total Utility Bills – Existing Office Building - Denver



Q. WOULD CHANGING SCHEDULE SG TO BE A PRIMARILY ENERGY-BASED RATE HAVE A LARGE IMPACT ON CUSTOMER BILLS?

A. Yes. While rates could be designed to collect approximately the same amount of total revenue under either rate structure, the impacts to individual customer bills could be large.

Q. HOW DOES THAT COMPARE TO THE IMPLEMENTATION OF SCHEDULE RE-TOU FOR RESIDENTIAL CUSTOMERS?

A. It is important to note that Schedule R and Schedule RE-TOU have generally similar rate structures in that they both are two-part rates where the majority of costs are collected through energy charges and the remainder collected through the fixed services and facilities ("S&F") charge. The difference between the two is that Schedule RE-TOU has time differentiated energy charges. As a result, and as further discussed by Mr. Knighten in his Direct Testimony, when Residential customers moved from flat energy charges to TOU energy charges, the annual bill impacts were narrowly distributed. Formulating Schedule SG as a primarily energy-based rate (whether TOU or otherwise) would be a far more radical change in rate structure and have a much broader impact on customers' bills.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE USE OF DEMAND CHARGES IN C&I SECONDARY RATE SCHEDULES?

A. Demand charges are reflective of cost causation on the distribution system and time differentiated demand charges are reflective of cost causation for generation and transmission in the same way that time of use energy charges are. Furthermore, demand charges are not a barrier to Colorado's electrification goals. This is because demand charges are beneficial to customers with high load factors and electrified heating should increase customer's load factors. Demand charges encourage customers to electrify in the lowest cost way possible. To avoid costly distribution investments, electrifying customers should be encouraged to avoid high spikes in their electric use and instead use electricity in a smooth, less volatile pattern. Rates with demand charges do exactly this by linking price signals to peak demand rather than overall consumption.

Further, energy-based rate design may become less appropriate going forward given the Company's evolving generation mix. With more renewable resources being added to our generation portfolio, the instances of curtailment events will only increase. Assessing energy charges to customers during curtailment events when the marginal cost of energy is zero or even negative is inconsistent with cost causation principles.

B. Time Differentiated G&T Demand Charges

Q. IS THE COMPANY PROPOSING TO INTRODUCE TIME DIFFERENTIATED DEMAND CHARGES FOR THE C&I SECONDARY CLASS IN THIS PROCEEDING?

A. Yes, as discussed further by Mr. Knighten, we are recommending that all C&I Secondary rate schedules that include G&T demand charges be migrated to time differentiated demand charges as customers receive Advanced Meters.[7]

Q. PLEASE DESCRIBE THE PROPOSED TIME DIFFERENTIATED DEMAND CHARGES FOR C&I SECONDARY RATE SCHEDULES.

A. We recommend that G&T demand charges be assessed from 2:00 PM to 7:00 PM on weekday non-holidays. The rate design mirrors the time differentiated demand charges the Company implemented for the main C&I Primary rate schedule (*i.e.*, Schedule PG) several years ago. By only assessing a demand charge during the on-peak window, the new rate structure will send a strong price signal to C&I Secondary customers to thoughtfully manage their usage.

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[7] 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. WHAT WILL BE THE IMPACT OF TIME DIFFERENTIATED DEMAND CHARGES FOR C&I SECONDARY CUSTOMERS?

A. The ultimate impact of this change is uncertain. However, the Company has observed that the time differentiated demand charges for Schedule PG have been effective in slowing the growth of peak demands in the 2:00 PM to 7:00 PM time period. Since the 2016 Phase II, when time differentiation was approved for Schedule PG, the total energy use of customers on Schedule PG has grown 1.2 percent. Distribution demand, which is measured on a non-coincident basis (*i.e.*, all hours), grew 1.1 percent. The 2:00 PM to 7:00 PM G&T demand charge volumes, however, have grown only 0.7 percent. If this slower growth rate is also realized in the C&I Secondary class, it could lead to a system peak demand reduction of almost 80 MW by 2030.

Table SWW-D-3
Growth Rate for Schedule PG Volumes

	2016 Phase II Rate Design	**2022 Actual**	**Growth Rate**
Energy	3,342,519,089 kWh	3,543,554,648 kWh	1.2%
Distribution Demand	6,983,466 kW-months	7,393,747 kW-months	1.1%
G&T Demand	6,531,156 kW-months	6,772,515 kW-months	0.7%

Q. HOW WILL THE TIME DIFFERENTIATED DEMAND CHARGES BE IMPLEMENTED?

A. The time differentiated demand charges will become effective after customers receive their Advanced Meter using an approach similar to that used in moving Residential and Small Commercial customers to TOU rates. Specifically, the

Company's proposed tariffs for Schedules SG and SG-CPP provide that the time differentiated G&T demand charges will begin being assessed in the first billing cycle beginning April 1 following receipt of their Advanced Meter.

Q. WILL THE TIME DIFFERENTIATED G&T DEMAND CHARGES BEGIN BEING ASSESSED IN 2024?

A. No. The first applicable billing cycle begins April 1, 2025. I believe waiting until 2025 to transition to time differentiated rates is appropriate given that a final decision in this proceeding is likely to be in early 2024 and the Company would need some time for customer outreach and education on the new rate structure before it is implemented.

Table SWW-D-4
SG Transition to Time Differentiated G&T Demand Charges

Advanced Meter Receipt	SG Time Differentiated Demand Charge Transition
On or before December 31, 2024	Billing cycle that includes April 1, 2025
January 1, 2025 and thereafter	Billing cycle that includes April 1 the year following receipt of Advanced Meter

IV. SMALL COMMERCIAL DEMAND THRESHOLD

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

A. In this section of my Direct Testimony, I present and discuss an analysis of the demand threshold used for Schedules C and C-TOU, which was required by the 2020 Phase II Decision.[8]

Q. HOW DOES THE SCHEDULE C-TOU/C DEMAND THRESHOLD AFFECT THE COMPANY'S SMALL C&I CUSTOMERS?

A. The demand threshold generally establishes the point at which a customer is no longer eligible to receive service under Schedules C-TOU and C: customers taking service at secondary voltage with demands greater than the demand threshold must take service under one of the secondary voltage rate schedules (*e.g.*, Schedule SG).[9] Conversely, customers taking service at secondary voltage with demands less than the threshold have the option to take service under Schedules C-TOU or C.

Q. WHAT IS THE CURRENT SCHEDULE C-TOU/C DEMAND THRESHOLD?

A. The current Schedule C-TOU/C demand threshold is 50 kW. This threshold was established in the 2020 Phase II and is higher than the previous threshold of 25 kW. This new threshold has been in place for less than two years.[10]

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[8] 2020 Phase II Decision at pp. 17-18, ¶ 39.

[9] If a Schedule C-TOU/C customer exceeds the 50 kW threshold by 20 percent or more (*i.e.*, has monthly demand of 60 kW or greater) or exceeds the 50 kW threshold by less than 20 percent more than one time, then the customer is transferred to Schedule SG.

[10] 2020 Phase II Decision at pp. 16-17, ¶ 38.

Q. WHAT IS THE PRIMARY DIFFERENCE BETWEEN SCHEDULES C-TOU/C AND SCHEDULE SG?

A. Schedule SG has a demand charge while Schedules C/C-TOU do not.

Q. WHY WOULD THIS DIFFERENCE MATTER TO SMALLER C&I CUSTOMERS?

A. The different rate structures present an opportunity for customers with demands that exceed the threshold and lower load factors to engage in rate arbitrage, whereby they switch to Schedule C-TOU or Schedule C to receive a lower rate without any change of behavior or lowering of system costs.

Q. IS THIS KIND OF RATE ARBITRAGE PROBLEMATIC?

A. Yes. In the short term, Schedule C-TOU/C rate arbitrage could lead to revenue erosion for the Company and trigger the filing of a new Phase I rate case to address the revenue deficiency. In the long term, inappropriate rate arbitrage could cause cost shifts within the Company's CCOSS from the C&I Secondary class to the Small Commercial class.

Q. HAS THIS KIND OF RATE ARBITRAGE COME TO PASS FOLLOWING THE 2020 PHASE II?

A. Somewhat. In the 2020 Phase II, the Company raised concerns that increasing the Schedule C-TOU/C demand threshold could result in short-term revenue erosion and long-term class cost shifts from Schedule C-TOU/C and Schedule SG.[11] As discussed below, both have come to pass to a certain extent.

[11] 2020 Phase II, Ex. 111 at 71:11-20 (Wishart Rebuttal).

Q. IS THERE EVIDENCE THAT SMALLER C&I CUSTOMERS ARE ENGAGING IN RATE ARBITRAGE AS A RESULT OF THE INCREASE IN THE SCHEDULE C-TOU/C DEMAND THRESHOLD?

A. Yes. From September 2021 (when the demand threshold was increased) through March 2023, the average load factor of customers that switched from Schedule SG to Schedules C-TOU/C has been approximately 25 percent. For comparison, the average load factor of Schedule SG customers is approximately 45 percent.

Q. HAS THE COMPANY TRACKED THE EFFECT OF THE INCREASE OF THE SCHEDULE C-TOU/C DEMAND THRESHOLD?

A. Yes. In the 2020 Phase II, the Commission authorized the Company to record any resulting revenue excess or shortfalls from Schedule SG to Schedule C-TOU/C migration for recovery in a later proceeding.[12] The Company started tracking customer shifts between Schedule SG and Schedules C-TOU/C and the net revenue erosion starting in September 2021, when rate changes from the 2020 Phase II were implemented. As of March 31, 2023, the Company has seen 1,639 customers switch from Schedule SG to Schedules C-TOU/C, with a reduction in base rate revenues of $1,782,402. 450 customers have also switched from Schedules C-TOU/C to Schedule SG with a revenue increase of $645,580. Taken together, the net revenue erosion through March 2023 is $1,136,822.

[12] 2020 Phase II Decision at p. 18, ¶ 40 ("With respect to the Company's concerns that the change in Schedule C/C-TOU demand threshold will invalidate or complicate the CCOSS, rate design, RDA pilot recovery, and may result in revenue shortfall, we find it appropriate for the Company to record any resulting revenue excess or shortfall in a regulatory account and address these issues in a future Phase I or Phase II rate proceeding, as appropriate.").

However, as discussed below, there are approximately 17,500 Schedule SG customers that are under 50 kW and who would have lower bills under Schedule C if they switched rates.

Q. DID THE COMPANY NOTIFY SG CUSTOMERS ABOUT THE NEW SCHEDULE C THRESHOLD?

A. Yes. Starting in May 2022, the Company began sending out email notifications to Schedule SG customers that were under the new Schedule C threshold of 50 kW and that likely would benefit by switching rates. Instead of notifying all customers at once, the notifications were sent in batches of about 100 to 1,000 per week to avoid the possibility that our customer service call center might receive an excessively large number of calls from customers all at once requesting to change rates. From May through November 2022, the Company sent out a total of 14,000 notifications to customers.

Q. DESPITE THIS OUTREACH, WHY HAVEN'T MORE SCHEDULE SG CUSTOMERS MOVED TO SCHEDULE C-TOU OR SCHEDULE C?

A. I do not know for sure, but one possible reason is related to the concept of "complacence." This concept is illustrated in a residential time of use pilot study conducted by the Sacramento Municipal Utility District ("SMUD") in 2011 to 2013. This study was particularly interesting in that there was a group of customers that were invited to opt-in to the pilot rate and another that was defaulted onto the pilot rate with an option to opt-out. The results showed that only 20 percent of customers elected to opt-in to the TOU option, while 90 percent of the customers who were automatically switched to the rate stayed on the rate. These results demonstrate that many electric customers are complacent and content to stay on the rate they are on. While the SMUD results for residential customers cannot be directly applied to C&I customers in Colorado, I believe there is a similar tendency for customers to choose to remain on their current rate schedule.

Q. WHAT OBLIGATION DOES THE COMPANY HAVE TO NOTIFY CUSTOMERS THAT THEY MIGHT NOT BE ON THE MOST ADVANTAGEOUS RATE SCHEDULE?

A. I am not aware that the Company has an obligation to move customers to rate schedules that would result in the lowest bills possible. Our electric tariff addresses this issue on Sheet R11 (an excerpt of which is provided below). While the Company will assist customers in selecting the best rate for them, the customer must request such assistance and the customer is responsible for the final rate selection.

Figure SWW-D-7
Electric Tariff Sheet R11 Excerpt

<u>CHOICE OF RATES</u>

The rate schedules are on file and available at the Principle Office of the Company and the Company's website. Applicant shall elect under which rate schedule service shall be supplied subject to the terms and conditions of the individual rate schedule. When there are two (2) or more rate schedules applicable to any class of service Company will, upon request of applicant, explain the conditions, character of installation or use of service governing the several rate schedules and assist in the selection of the rate schedule most suitable for applicant's requirements. Applicant, however, shall be responsible for the final selection of said rate schedule, and Company assumes no liability therefore.

Q. WOULD IT BE A GOOD IDEA TO PROACTIVELY MOVE CUSTOMERS TO THE RATE THAT RESULTED IN THE LOWEST POSSIBLE BILL?

A. No. If all customers were moved to the rate that resulted in the lowest possible bill, the results would be a large reduction in revenue for the Company, which would in turn would result in another Phase I rate case to increase rates for all customers. It makes little sense to lower bills for a subset of customers and subsequently raise rates for all customers.

Q. HAS THE COMPANY ESTIMATED THE REVENUE EROSION THAT COULD OCCUR IF THE SMALL COMMERCIAL DEMAND CAP IS RAISED TO 75 KW OR 100 KW?

A. Yes. I analyzed billing data from Schedule SG customers to identify how many customers could lower their bills by switching from Schedule SG to Schedule C and how large the revenue impact would be. I also calculated what the impact would be if all Schedule SG customers of a given size were moved from Schedule SG to Schedule C. The results show that in 2022, there were about 17,500 Schedule SG customers under 50 kW who could have lowered their electric bill by switching to Schedule C. The associated revenue erosion if that would have occurred is approximately $32 million. For customers between 50 kW and 75 kW there is the potential for an additional $11 million in revenue erosion and for customers between 75 kW and 100k W there is the potential for an additional $6.7 million in revenue erosion. The following table summarizes the results of that analysis.

Table SWW-D-5
Impacts of Customer Moving from Schedule SG to Schedule C

Annual Peak Demand	Customer Who Would Benefit From Switching From SG to C		If All SG Customer Are Moved to C	
	Count	Revenue Erosion	Count	Revenue Erosion
0kW - 25kW	9630	($13,198,765)	12,903	($9,932,828)
25kW - 50kW	8024	($19,122,740)	11,886	($11,754,917)
50kW - 75kW	3071	($11,214,612)	5,197	($3,952,447)
75kW - 100kW	1370	($6,698,258)	2,711	$27,947
100kW - 125kW	774	($4,808,185)	1,680	$1,506,483
125kW - 150kW	537	($4,054,682)	1,294	$2,608,602
150kW - 175kW	378	($3,787,427)	931	$2,281,918
175kW - 200kW	324	($3,516,040)	746	$2,390,758
200kW - 225kW	240	($3,004,220)	587	$2,497,120
225kW - 250kW	186	($2,488,594)	472	$3,271,013
250kW - 275kW	135	($1,850,051)	404	$3,928,276
275kW - 300kW	107	($1,769,683)	338	$4,048,597
300kW - 325kW	79	($1,371,712)	266	$4,330,899
325kW - 350kW	70	($1,103,285)	249	$4,598,029
350kW - 375kW	60	($948,389)	225	$5,235,827
375kW - 400kW	61	($1,073,551)	190	$3,389,498
400kW - 425kW	53	($1,125,429)	149	$3,264,342
425kW - 450kW	39	($761,627)	161	$4,578,195
450kW - 475kW	34	($730,996)	146	$4,226,837
475kW - 500kW	28	($609,156)	104	$3,158,008

Q. AT WHAT LOAD FACTOR DOES SCHEDULE C BECOME A LOWER COST OPTION FOR C&I CUSTOMERS?

A. There are a few factors that can impact the precise load factor at which Schedule C becomes a lower cost option that Schedule SG, such as seasonal variation in load and the absolute size of the customer. But for a 50 kW customer with consistent load throughout the year, I estimate that the breakeven load factor is 45.5 percent. The following table summarizes that calculation.

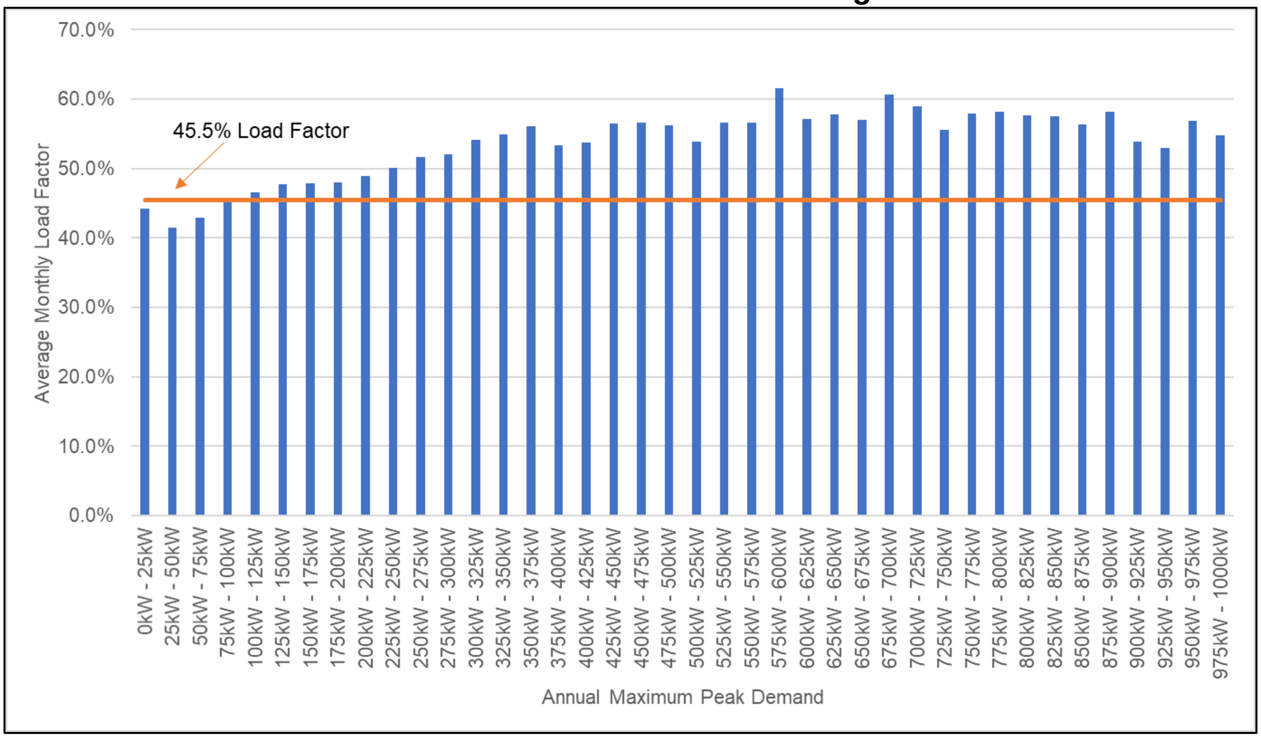
Table SWW-D-6
Schedule SG vs Schedule C Breakeven Load Factor

Peak Demand	Load Factor			
50 kW	45.5%			
	Schedule C	**Volumes**		
S&F	$10.50/month	12 months		$126
Summer	$0.11313/kWh	66,350 kWh		$7,506
Winter	$0.06811/kWh	132,701 kWh		$9,038
			Total	**$16,670**
	Schedule SG	**Volumes**		
S&F	$70.28/month	12 months		$843
Energy	$0.00939/kWh	199,051 kWh		$1,869
Distribution	$9.85/kW-mo	600 kW-months		$5,910
Summer	$18.26/kW-mo	200 kW-months		$3,652
Winter	$10.99/kW-mo	400 kW-months		$4,396
			Total	**$16,670**

Q. WHAT IS THE DISTRIBUTION OF LOAD FACTORS FOR SCHEDULE SG CUSTOMERS?

A. To answer this question, I utilized a comprehensive set of 2022/23 billing data for Schedule SG customers. I sorted the customers by their annual peak demand and calculated the average load factor for customer in tranches of 25 kW. The result generally showed that smaller customers had lower load factors. The following figure illustrates the results and includes the approximate 45.5 percent breakeven load factor.

Figure SWW-D-8
SG Customer Peak Demand and Average Load Factor



Q. WHAT IS THE DISTRIBUTION OF CUSTOMER LOAD FACTORS FOR SCHEDULE SG CUSTOMERS BETWEEN 50 KW AND 75 KW AND THE DISTRIBUTION OF CUSTOMER LOAD FACTORS BETWEEN 75 KW AND 100 KW?

A. Using the same data set I discussed above, I developed histograms illustrating the distribution of load factors for Schedule SG customers with peak demands between 50 kW and 75 kW and then for Schedule SG customers with peak demands between 75 kW and 100 kW. The following figures show that the distribution of average annual load factors for Schedule SG customer between 50 kW and 100 kW are roughly evenly distributed around the 45.5 percent breakeven load factor between Schedule SG and Schedule C.

Figure SWW-D-9
Schedule SG Customer
Load Factor Distribution
50 kW to 75 kW

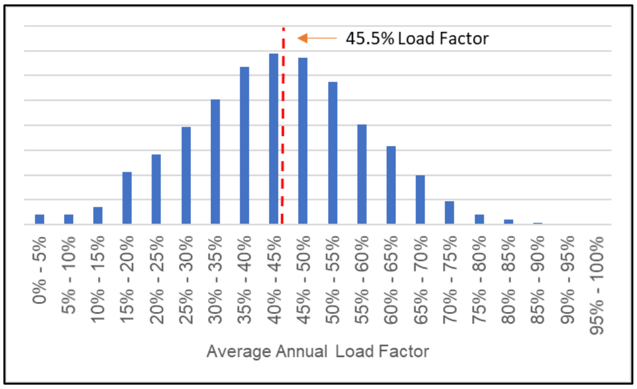
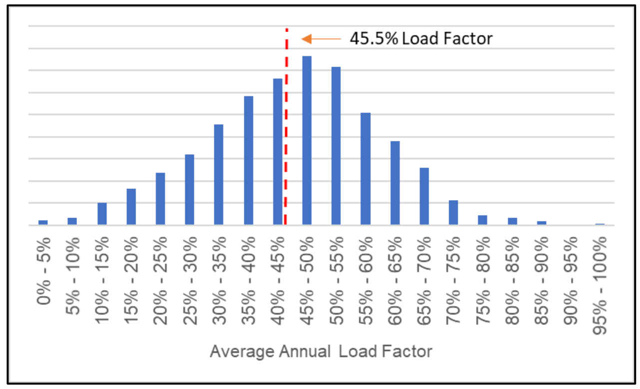


Figure SWW-D-10
Schedule SG Customer
Load Factor Distribution
75 kW to 100 kW



Q. WHAT DO YOU RECOMMEND FOR THE SCHEDULE C-TOU/C DEMAND THRESHOLD?

A. I recommend that the current demand threshold of 50 kW be maintained going forward. There is no justifiable reason to create additional opportunity for rate arbitrage. The Company already has tracked $1,136,822 in revenue erosion from the decision to change the Small Commercial threshold from 25 kW to 50 kW. These are real cost that will eventually need to be recovered from other customers.

Q. WILL THE COMPANY CONTINUE TO TRACK REVENUE EROSION ASSOCIATED WITH CUSTOMER MOVING FROM SCHEDULE SG TO SCHEDULES C OR C-TOU?

A. Yes. The 2020 Phase II Decision authorized the Company to create a regulatory account to address customers moving from Schedule SG to Schedules C-TOU/C.[13] To date, customer movement has resulted in $1,136,822 of revenue

[13] 2020 Phase II Decision at 18, ¶ 40.

erosion. The Company will continue to track lost revenue and will bring the deferred amounts forward for recovery in a future proceeding.

V. ECONOMIC DEVELOPMENT RATE

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

A. The purpose of this Section of my Direct Testimony is to present the Company's updated marginal cost analysis in response to the Commission's approval of the Company's economic development rate ("EDR") program in Decision No. C21-0333 in Proceeding No. 20A-0345E (the "EDR Proceeding").[14] I demonstrate that the marginal cost of serving new economic development customers is relatively unchanged from Proceeding No. 20A-0345E and that the current base rate discounts provided to EDR customers still result in revenues that are above marginal cost.

Q. WHAT ARE THE MARGINAL COST REQUIREMENTS DETAILED IN DECISION NO. C21-0333?

A. As reflected in Decision No. C21-0333, the Commission will reassess the Company's long-term marginal cost calculations for customer, distribution, transmission, generation, and corporate services in future Phase II electric rate case proceedings. As part of this proceeding, the Company is required to reassess its use of combustion turbine technology in calculating incremental generation capacity cost.[15]

[14] EDR Proceeding, Decision No. C21-0333, (Mailed date June 7, 2021). Decision No. C21-0333 modified and clarified the Unopposed and Partial Settlement Agreement among the Company, Trial Staff ("Staff") of the Commission and the Colorado Office of Consumer Counsel (now the Colorado Office of the Utility Consumer Advocate) (the "EDR Proceeding Settlement"). The EDR Proceeding Settlement is Attachment A to Decision No. C21-0333.
[15] EDR Proceeding Settlement at 11.

Q. HOW WILL REVENUE FROM THE COMPANY'S ECONOMIC DEVELOPMENT RATE PROGRAM BE ALLOCATED IN A CCOSS?

A. In future Phase II electric rate case proceedings, EDR customer counts, monthly peak demands, and total sales quantities will be excluded from the class cost allocation analysis. EDR revenues will be treated as a revenue credit to the revenue requirement.[16] However, there is no EDR load in the Test Year, nor is there any EDR load in the 2022 IHTY.[17] As such this provision does not impact this proceeding.

Q. IS A COMBUSTION TURBINE STILL THE APPROPRIATE BASIS FOR ESTABLISHING THE INCREMENTAL COST OF CAPACITY AT THIS TIME?

A. Yes. At this time, I recommend continuing to use the generic combustion turbine cost from the 2021 Electric Resource Plan ("ERP"), Proceeding No. 21A-0141E, as the basis for the marginal capacity cost in economic development rate analysis. However, the time to calculate the incremental cost of capacity based on battery storage technology may be soon.

Q. PLEASE DISCUSS THE CURRENT STATUS OF THE ERP.

A. The Company currently is evaluating generation bids in the second phase of the ERP. On March 31, 2023, the Company filed its 30-day report in the Phase II ERP proceeding. That report lists the median bid price received for various generation

[16] EDR Proceeding, Decision No. C21-0333, Attachment A at 17.
[17] As discussed by Mr. Knighten, the Company presently is seeking Commission authorization in the 2022 Phase I 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"). In the Company's Supplemental Direct Testimony in the 2022 Phase I, the Company also provided information regarding an informational historical test year ending December 31, 2022 (the "2022 IHTY").

technologies. The Company received 13 bids for gas generation with a median price of $10.65/kW-month and 80 bids for energy storage with a median bid price of $12.14/kW-month. It is possible that the final Commission-approved portfolio of new resources will not include combustion turbines.

Q. DO YOU RECOMMEND USING THE MEDIAN PRICES FROM THE 30-DAY REPORT IN THE EDR ANALYSIS?

A. No. I do not recommend using either of these values as the median price is likely above the lowest cost bids that will ultimately be selected.

Q. WHAT COSTS DID THE COMPANY USE?

A. The Company updated the marginal cost of generation capacity based on the cost of a generic combustion turbine from the 2021 ERP. The new cost is considerably higher than the cost used in the EDR Proceeding. This is because in the analysis in the EDR Proceeding included several years where the Company expected to have excess capacity and the marginal cost of generation capacity was set very low. In the current analysis, we've specified the full cost of a combustion turbine in every year.

Q. HAS THE COMPANY REEVALUATED THE MARGINAL COST OF TRANSMISSION AND DISTRIBUTION FOR PURPOSES OF THE EDR ANALYSIS?

A. Yes, the Company performed an analysis that is nearly identical to the analysis that I presented in the original EDR Proceeding. The analysis starts with a baseline load forecast and planned distribution and transmission upgrades. Then 100 MW of new load is spread over 10 substations and over 10 years and the system is reevaluated to identify incremental investments that would be needed to serve that incremental load.

Just like in the EDR Proceeding, this analysis did not identify any needed incremental transmission investments. However, the analysis did identify substantially more distribution investments. The previous study from the EDR Proceeding identified an incremental $45 million of distribution investments to support an incremental 100 MW of new load. The updated analysis identified $86 million in incremental investments to support an incremental 100 MW of new load.

Q. HAS THE COMPANY UPDATED ITS ESTIMATE OF CORPORATE SERVICES FOR PURPOSES OF THE EDR ANALYSIS?

A. Yes, the corporate service costs allocated to Public Service based on both revenue and load were updated for this analysis. The updated value is $0.00020/kWh, a small increase from the $0.00016/kWh that was used in the EDR Proceeding.

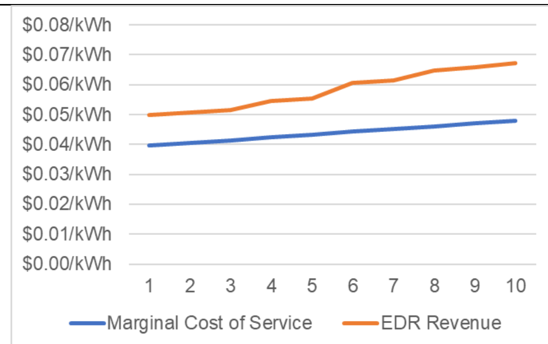
Q. WHAT IS THE OVERALL CHANGE TO THE MARGINAL COST TO SERVE EDR CUSTOMERS?

A. Although some of the marginal cost estimates have increased, the revenue received from EDR customers will still be above the marginal cost to serve them, which is required by statute. I have included the marginal cost analysis as Attachment SWW-2 and the results are summarized below.

TABLE SWW-D-7
EDR Marginal Cost Rates

	EDR Proceeding	Updatead Values
Customer	Class Specific	
Distribution	$3.50/kW-month	$7.67/kW-month
Transmission	$0.00/kW-month	$0.00/kW-month
Generation	$4.13/kW-month	$7.63/kW-month
Corporate Services	$0.00016/kWh	$0.00020/kWh

Figure SWW-D-11
Marginal Cost of Service versus EDR Revenue



VI. BILL IMPACTS & AFFORDABILITY METRICS

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

A. This section of my Direct Testimony presents the overall bill impact analysis and addresses the Commission's request that the Company present certain affordability metrics. I describe different affordability metrics, explain the analysis prepared to date, and discuss the results of the Company's analysis.

A. Bill Impacts

Q. HOW DID YOU DERIVE BILL IMPACTS ASSOCIATED WITH THE COMPANY'S PHASE II PROPOSAL?

A. I calculated two sets of bill impacts. The first compares current rates absent the Company's pending 2022 Phase I proposals to the new rates derived by Mr. Knighten. This version essentially presents the bill impacts of both the Phase I portion of the rate case and the Phase II portion of the rate case.[18] The second analysis compares current rates plus the General Rate Schedule Adjustments ("GRSAs") that the Company recommended its 2022 Phase I Direct Testimony to the Phase II rates. This second analysis isolates the impacts of the recommendations we are making in the Phase II proceeding. The bill impact analysis utilized current base rates and riders to calculate total average monthly bills for the five largest rate schedules (Schedules RE-TOU, C, SG, PG, and TG).

[18] The Phase I proposals are those from the Company's Direct Testimony in the 2022 Phase I.

Q. WHAT ARE THE EXPECTED IMPACTS ON CUSTOMER BILLS AS A RESULT OF THE COMPANY'S PROPOSED ELECTRIC RATES?

A. I provide a detailed bill impact analysis as Attachment SWW-3 to my Direct Testimony. The table below summarizes the estimated change in monthly bills that would result from the combination of the Company's proposals in both the Phase I (Direct Testimony) and Phase II proceedings. The combination of the base rate increase proposed in Phase I with the associated roll-in of costs from the transmission cost adjustment ("TCA") and purchased capacity cost adjustment ("PCCA"), and the cost allocation and rate design proposed in this proceeding, result in monthly bill impacts ranging from 3.2 percent to 9.6 percent. The variation in bill impacts reflects both changes in class cost allocation as well as the proportion of total bills that are base rate charges.

Table SWW-D-8
Impact of Phase I and Phase II Proceedings

	Current Bill	Proposed Bill	Monthly $ Change	Monthly % Change
Residential - RE-TOU	$86.94	$95.31	$8.37	9.6%
Small Commercial - C	$129.80	$134.08	$4.28	3.3%
Secondary General - SG	$2,445.57	$2,636.96	$191.39	7.8%
Primary General - PG	$41,950.96	$43,337.10	$1,386.14	3.3%
Transmission General - TG	$521,730.63	$558,130.32	$36,399.69	7.0%

The second bill impact analysis that I conducted isolated the impact of just the cost allocation and rate design proposals in this Phase II. For this analysis the baseline for comparison included the GRSA and GRSA-Energy charges that the Company proposed in Phase I Direct Testimony. Those average bills are then compared to average bills based on the new base rate charges recommended by

Mr. Knighten. The bill impact results of just the Phase II recommendations range from -4.7 percent to +0.9 percent.

Table SWW-D-9
Impact of Phase II Cost Allocation & Rate Design

	Phase I Bill	Phase II Bill	Monthly $ Change	Monthly % Change
Residential - RE-TOU	$94.52	$95.31	$0.78	0.8%
Small Commercial - C	$140.66	$134.08	($6.58)	-4.7%
Secondary General - SG	$2,637.93	$2,636.96	($0.97)	0.0%
Primary General - PG	$44,853.13	$43,337.10	($1,516.03)	-3.4%
Transmission General - TG	$552,973.56	$558,130.32	$5,156.76	0.9%

Q. CAN YOU EXPLAIN THE VARIATION IN THE PHASE II BILL IMPACTS ACROSS THE CUSTOMER CLASSES?

A. Yes. The final bill impacts primarily are a result of the class cost allocation process, but they are also impacted by changes in sales volumes and rate design. Residential bills are expected to increase slightly as a result of our Phase II proposals. This is largely due to the increase in customer-related costs.

Q. PLEASE ADDRESS THE INCREASE IN CUSTOMER-RELATED COSTS.

A. Mr. Klingeman provides a comparison between functionalized revenue requirements from this proceeding and functionalized revenue requirements from the 2020 Phase II.[19] That comparison shows that customer-related costs such as meters and billing had the largest percentage increase. Because the Residential class has the largest number of customers, it receives a majority of customer-related cost allocations. I also note that the increase in average Residential bills would have been greater if the CCOSS was performed using the 4CP-AED

[19] Hrg. Ex. 102, Table DSK-D-7 (Klingeman Direct).

allocation methodology. Specifically, I estimate that the average Residential customer's bill increase would be 3.2 percent if the Company had used the 4CP-AED allocation methodology, rather than the 0.8 percent increase shown in Table SWW-D-9, above, as a result of using the POD-PH methodology. Finally Residential rates also have upward pressure with the elimination of the $15 million rate mitigation adjustment that was part of the 2020 Phase II Stipulation and Settlement Agreement (the "2020 Phase II Partial Stipulation") ultimately approved in the 2020 Phase II.[20].

Q. PLEASE DISCUSS THE CHANGE IN SMALL COMMERCIAL BILLS AS A RESULT OF THE COMPANY'S PHASE II PROPOSALS.

A. Small Commercial bills are expected to have the largest bill decreases, with a Phase II bill decrease of 4.7 percent. In contrast to the Residential class, Small Commercial customers realized a significant decrease in customer-related costs since the 2020 Phase II. Their allocated share of service laterals fell from 11 percent to 5 percent as a result of allocating those costs based on sum of individual maximum demands, as discussed by Mr. Klingeman.[21] The Small Commercial share of meter costs also fell. This is because a majority of Advanced Meter deployment in the Test Year will be for the Residential class, meaning that the meter cost allocation for other classes is generally lower. For Small Commercial customers their share of meter costs fell from 11 percent to 9 percent. Overall, the

[20] Proceeding No. 20AL-0432E, Decision No. 21R-0400, pp. 26-32, ¶¶ 57-73 (Mailed Date: July 12, 2021).
[21] Hrg. Ex. 102, Sections III.D.5, IV.B.3 and Table DSK-D-11 (Klingeman Direct).

allocated customer related costs for Small Commercial fell by about 2 percent, while the total number of customers increased by 5 percent.

Small Commercial customers also benefit from the introduction of the POD-PH allocation methodology. In the 2020 Phase II, Small Commercial customers were allocated 5.1 percent of production capacity, transmission, and substation costs using the 4CP-AED methodology. In this case, the POD-PH approach resulted in an allocation of only 4.5 percent.

Q. PLEASE DISCUSS SECONDARY GENERAL BILL IMPACTS.

A. For the Schedule SG, the Phase II bill impacts were approximately zero. While this class did see increased cost allocation associated with distribution costs, that increase was offset by a lower allocation of production energy and customer-related costs. Secondary General also benefited from the elimination of the rate mitigation adjustment from the 2020 Phase II Partial Stipulation.

Q. WHY DOES THE SECONDARY GENERAL CLASS HAVE A LOWER ALLOCATION OF PRODUCTION ENERGY COSTS?

A. For production capacity and transmission, the current POD-PH and the 2020 Phase II 4CP-AED methodologies allocate approximately the same share of costs to Secondary General customers. However, the POD-PH methodology is also applied to production energy costs, which consist of two large wind farms and variable O&M at other power plants. Formerly these costs had been allocated using total annual energy consumption for each class. For the approximate $290 million in production energy costs, the Secondary General allocation share fell from 42 percent to 38 percent. So, increasing distribution costs, approximately flat production capacity costs, decreasing production energy costs, and elimination of the rate mitigation adjustment, resulted in Phase II impacts for Secondary General customers that were essentially flat.

Q. PLEASE DISCUSS PRIMARY GENERAL BILL IMPACTS.

A. For the Schedule PG, the Phase II cost allocation and rate design resulted in an approximate 3.4 percent decrease in average monthly bills. The POD-PH methodology did result in an increase in production capacity costs, but it also resulted in an equivalent decrease in production energy costs.

Q. WHAT IS THE PRIMARY CAUSE IN THE DECREASE IN AVERAGE MONTHLY SCHEDULE PG BILLS?

A. The decrease in Primary General average bills primarily was driven by the change from GRSA adjustments to actual cost allocation. With GRSA adjustments, all increased costs are assessed to all rate classes, meaning the C&I Primary class was being assessed some incremental secondary voltage distribution, as well as a large share of customer-related costs. Through the class cost allocation process, no secondary voltage distribution costs were assessed to the Primary General customers and customer related costs were significantly reduced. Finally, average bills were also lowered through the elimination of the rate mitigation adjustment from the 2020 Phase II Partial Stipulation.

Q. PLEASE DISCUSS THE SCHEDULE TG AVERAGE BILL IMPACTS.

A. There was a small average Schedule TG bill increase of 0.9 percent as a result of the Phase II class cost allocation and rate design. Like C&I Primary, the C&I Transmission class does benefit from the elimination of the GRSA and removal of distribution charges from its bills and a large reduction in customer-related costs. However, the POD-PH methodology increases the allocation of production capacity costs more than it reduces the allocation of production energy costs for this class.

B. Affordability Metrics

Q. HOW HAVE YOU ASSESSED THE AFFORDABILITY FOR RESIDENTIAL CUSTOMERS?

A. Decision No. C23-0146-I from the 2022 Phase I ("2022 Phase I Supplemental Direct Decision") requested that the Company study various measures of affordability. Specifically, the Commission asked the Company to analyze three different affordability metrics: (1) energy cost burden; (2) affordability ratio; and (3) hours at minimum wage. The Commission also requested the Company's Supplemental Direct Testimony address how these metrics could be applied in this proceeding.[22] I sponsored Supplemental Direct Testimony in the 2022 Phase I proceeding and concluded that the three metrics above all provide lenses through which to consider the impacts of various proposals in the 2022 Phase I, as well as those made in this Phase II and the Company committed to include similar affordability metrics in this proceeding.[23]

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[22] Proceeding No. 22AL-0503E, Decision No. C23-0146-I (Mailed Date: March 1, 2023) at 4-6, ¶ 10-15.
[23] Proceeding No. 22AL-0530E, Hrg. Ex. 128 at 47:4-48:4 (Wishart Supplemental Direct).

Q. DO THE COMPANY'S PHASE II RECOMMENDATIONS IMPACT AFFORDABILITY FOR RESIDENTIAL CUSTOMERS?

A. No. As shown in Table SWW-D-9, above, the Company's Phase II recommendations have relatively small impacts on Residential customers and, as a result, will not have a large impact on affordability for our customers.

1. Energy Cost Burden

Q. PLEASE DESCRIBE THE ENERGY COST BURDEN METRIC.

A. The Supplemental Direct Decision identifies the energy cost burden metric as emanating from the January 2022 report *Pathways to Energy Affordability in Colorado* (the "Pathways to Energy Affordability Report"), prepared for the Colorado Energy Office ("CEO"). In that report, the authors define energy cost burden as "the percentage of household income spent on residential energy needs."[24]

Q. DID THE COMPANY PREPARE AN ENERGY COST BURDEN ANALYSIS FOR PHASE I SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes. As noted above, I sponsored Supplemental Direct Testimony in the 2022 Phase I where I presented an energy cost burden analysis.

Q. PLEASE DESCRIBE THAT ANALYSIS.

A. At a high level, I collected annual bills for all Public Service Residential customers and compared those to median household income by census block. I am aware that some parties in the 2022 Phase I proceeding filed answer testimony regarding

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[24] Physicians, Scientists, and Engineers for Healthy Energy and the Institute for Energy and Environmental Research, *Pathways to Energy Affordability in Colorado* (Jan. 2022) at 1, https://drive.google.com/file/d/1oTnkG1oiDrLrtoU9Ay7Se7bBbvG0KNcp/view?authuser=1.

how the analysis was conducted. However, given the short amount of time between when the Answer Testimony was filed in the 2022 Phase I and when this Phase II Direct Testimony was due, I have not revised my approach to calculating energy cost burden. I will address the 2022 Phase I Answer Testimony though Rebuttal Testimony in the 2022 Phase I.

Q. WHAT WERE THE RESULTS OF THE ENERGY COST BURDEN ANALYSIS?

A. After accounting for the Company's Phase I proposals, there were only a small number of customers that we identified as energy burdened or energy impoverished. The following table summarize the results of the Phase I analysis.

TABLE SWW-D-10
Results of Electric Energy Burden Analysis – Phase I

CEO Energy Burden Category	Number of Premises	Percentage of Total
Not Energy Burdened (less than 4%)	1,256,384	97.4%
Energy Stressed (4% to 7%)	28,020	2.2%
Energy Burdened (7% to 10%)	3,743	0.3%
Energy Impoverished (greater than 10%)	1,424	0.1%

Q. HAVE YOU UPDATED THE ENERGY BURDEN ANALYSIS WITH THE IMPACT OF THE COMPANY'S PHASE II RECOMMENDATIONS?

A. Yes. I increased customer annual bills by the 0.8 percent identified in the average bill impact analysis shown in Table SWW-D-10, above. As expected, such a small change in bills had a commensurately small impact on the energy burden analysis.

Table SWW-D-11
Results of Electric Energy Burden Analysis – Phase II

CEO Energy Burden Category	Number of Premises	Percentage of Total
Not Energy Burdened (less than 4%)	1,255,613	97.4%
Energy Stressed (4% to 7%)	28,663	2.2%
Energy Burdened (7% to 10%)	3,837	0.3%
Energy Impoverished (greater than 10%)	1,458	0.1%

2. Affordability Ratio

Q. PLEASE EXPLAIN THE AFFORDABILITY RATIO METRIC.

A. The affordability ratio ("AR") metric "quantifies the percentage of a representative household's income that would be used to pay for an electric utility service, after non-discretionary expenses such as housing and other essential utility service charges are deducted from the household's income."[25] The Supplemental Direct Decision directed that the Company calculate the AR metric with and without the Company's Phase I requests, for a Residential customer with average annual usage and for a Residential customer with median annual usage.

Q. HOW DID THE COMPANY CALCULATE THE AR METRIC?

A. The difficult aspect of this affordability calculation is the definition of "non-discretionary expenses." I was unable to find a clear definition of what expenses are defined as discretionary and which are non-discretionary. Also, the Company has limited insights into the spending patterns of our customers. In an effort to comply with the Commission's request, I was able to identify a Bureau of Labor

[25] Supplemental Direct Decision at 5-6, ¶ 13. The Decision points to the California Public Utilities Commission Affordability Rulemaking as a source for establishing the AR metric. Information regarding that rulemaking is available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

Statistics survey of consumer expenditures for 2020-2021.[26] The following table shows a summary of the results of that survey.

Table SWW-D-12
Bureau of Labor Statistics Survey of Consumer Expenditures 2020-2021

	United States	Denver
Income before taxes	$85,906	$103,708
Average annual expenditures	$64,187	$75,132
Total	100	100
Food	**12.2**	**11.2**
Alcoholic beverages	0.8	1.1
Housing	**34.3**	**36.2**
Apparel and services	2.5	1.8
Transportation	**16.2**	**16.3**
Healthcare	**8.3**	**7.5**
Entertainment	5.1	5.5
Personal care products and services	1.1	1.2
Reading	0.2	0.2
Education	1.9	1.9
Tobacco products and smoking supplies	0.5	0.3
Miscellaneous	1.5	1.2
Cash contributions	3.7	3.6
Personal insurance and pensions	11.8	12

This table indicates that food and housing account for 47.4 percent of total annual expenditures. For purposes of my analysis, I considered food, housing, transportation, and healthcare to be non-discretionary expenses, leaving the remaining 71.2 percent of annual expenditures as being available to meet

[26] U.S. Bureau of Labor Statistics, *Consumer Expenditures for the Denver Metropolitan Area – 2020-21*, https://www.bls.gov/regions/mountain-plains/news-release/consumerexpenditures_denver.htm (last accessed March 27, 2023).

electricity needs. I then compared the amount of non-discretionary expenditure to annual electric bills for a Residential customer with median and mean usage.[27]

Overall, electric service represents about two and a half percent of discretionary spending, and the Company's Phase I proposal would increase that amount by two tenths of a percent. Clearly these results depend on the assumed level of income and non-discretionary spending.

Table SWW-D-13
Affordability Ratio: Electric Service ÷ Discretionary Spending

	Usage	2022 Annual Bill	Annual Bill With Phase I Increase	Annual Bill With Phase I&II Increase
Mean Usage	7,301	$1,035	$1,120	$1,129
Median Usage	6,189	$888	$960	$968

Annual Expenditures	$75,132
Non-Discretionary Spending	47.40%
Discretionary Income	$39,519

Mean Usage	2022 Annual Bill	Annual Bill With Phase I Increase	Annual Bill With Phase I&II Increase
Electric Bill	$1,035	$1,120	$1,129
Share Of Discretionary Spending	2.6%	2.8%	2.9%

Median Usage	2022 Annual Bill	Annual Bill With Phase I Increase	Annual Bill With Phase I&II Increase
Electric Bill	$888	$960	$968
Share Of Discretionary Spending	2.2%	2.4%	2.4%

3. Hours at Minimum Wage

Q. PLEASE EXPLAIN THE HOURS AT MINIMUM WAGE METRIC.

A. The hours at minimum wage ("HM") metric "quantifies the hours of earned employment at the city minimum wage necessary for a household to pay for

[27] Based on 2022 sales, the mean annual usage for a Residential customer was 7,301 kWh and the median annual usage for a Residential customer was 6,189 kWh.

electric utility service charges."[28] The Supplemental Direct Decision requires the Company to calculate the HM metric with and without the proposed Phase I increase, for both the state minimum wage and the local minimum wage applied by the City and County of Denver.

Q. HOW DID THE COMPANY CALCULATE THE AR METRIC?

A. The Colorado minimum wage is $13.65 per hour[29] and the City and County of Denver minimum wage is $17.29 per hour.[30] Using these wages, a person would have to work five to six hours a month to pay for their electric service at the mean usage level and four to five hours at the median usage level. The Company's Phase I proposal would add 0.4 to 0.5 hours to that metric and the Phase II recommendations would add fewer than six minutes to that metric.

[28] Supplemental Direct Decision at 6, ¶14.
[29] https://cdle.colorado.gov/wage-and-hour-law/minimum-wage#:~:text=Federal%20minimum%20wage%20is%20currently,law%20beginning%20January%201%2C%202023.
[30] https://denvergov.org/Government/Agencies-Departments-Offices/Agencies-Departments-Offices-Directory/Auditors-Office/Denver-Labor/Citywide-Minimum-Wage/.

Table SWW-D-14
Hours at Minimum Wage Metric

Mean Usage	2022 Bill	Bill With Phase I Increase		Bill With Phase I&II Increase	
Annual Bill	$1,035	$1,120		$1,129	
Monthly Bill	$86.25	$93.32		$94.07	
Colorado Minimum Wage 2023	$13.65	$13.65	**Change**	$13.65	**Change**
Hours at Minimum Wage (HM)	6.3 hours	6.8 hours	0.5 hours	6.9 hours	0.05 hours
Denver Minimum Wage 2023	$17.29	$17.29	**Change**	$17.29	**Change**
Hours at Minimum Wage (HM)	5.0 hours	5.4 hours	0.4 hours	5.4 hours	0.04 hours

Median Usage	2022 Bill	Bill With Phase I Increase		Bill With Phase I&II Increase	
Annual Bill	$888	$960		$968	
Monthly Bill	$73.97	$80.03		$80.67	
Colorado Minimum Wage 2023	$13.65	$13.65	**Change**	$13.65	**Change**
Hours at Minimum Wage (HM)	5.4 hours	5.9 hours	0.4 hours	5.9 hours	0.05 hours
Denver Minimum Wage 2023	$17.29	$17.29	**Change**	$17.29	**Change**
Hours at Minimum Wage (HM)	4.3 hours	4.6 hours	0.4 hours	4.7 hours	0.04 hours

Q. DID THE COMPANY INVESTIGATE CREATING A SEPARATE CUSTOMER CLASS FOR INCOME QUALIFIED CUSTOMERS?

A. Yes. We analyzed the energy usage of income qualified[31] Residential customers to assess whether their usage was sufficiently dissimilar to that of the broader Residential customer class merit creation of a separate customer class. To justify a separate customer class, the load patterns load patterns for income qualified customer would have to be materially different than other Residential customers. For example, if income qualified customers had less demand during on-peak hours, then they would receive lower cost allocation and a lower average rate.

[31] For purposes of this analysis, "income qualified" customers are those that are eligible for the Company's Electric Affordability Program ("EAP").

As shown below, the aggregate load pattern of customers enrolled in the Company's EAP is not significantly different than the load pattern of the broader Residential customer class. It does appear that the winter (October through May) usage for EAP customers is a bit higher than the broader Residential class, but that would not result in a meaningfully different cost allocation because a customer group's load shape is more important than its absolute magnitude in the cost allocation process.

Figure SWW-D-12
All Residential versus EAP Average Load Shapes – Summer 2022

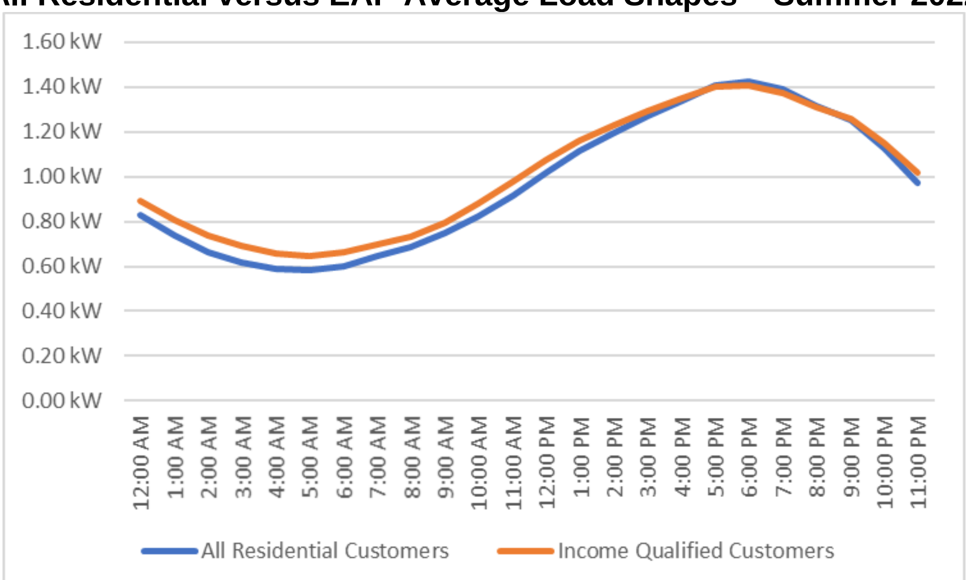
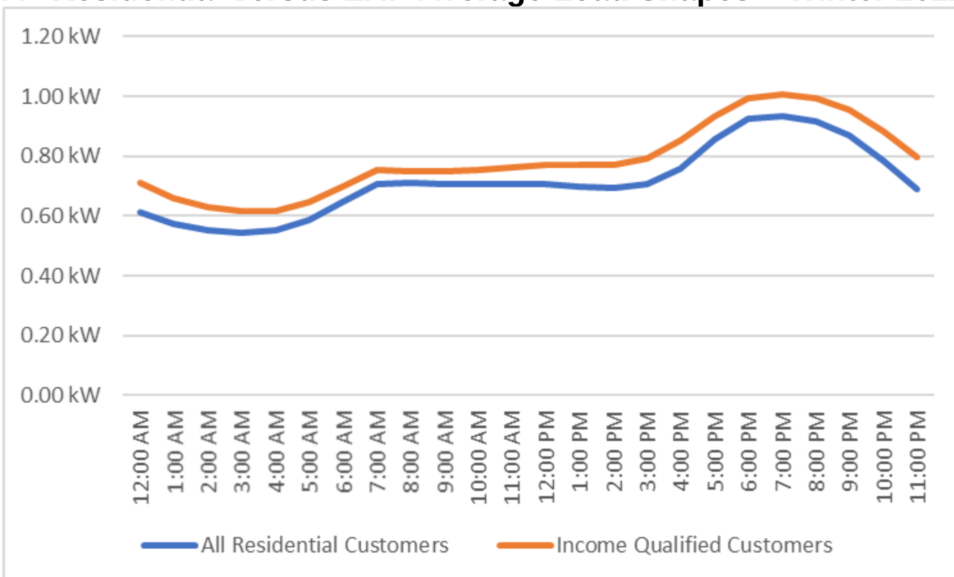


Figure SWW-D-13
All Residential versus EAP Average Load Shapes – Winter 2022



Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Steven W. Wishart

I began my employment with Xcel Energy Services, Inc. in 2005, in the Company's Demand-Side Management department. I am currently the Director of the Public Service Pricing and Planning team. My responsibilities include quantitative analyses, cost allocation, and rate design, and policy support on a number of Colorado regulatory issues.

Prior to taking my current position, I worked for Xcel Energy Services Inc. in Minneapolis, Minnesota, as Director of Resource Planning and Bidding for the Northern States Power region. In that role, I oversaw resource planning and resource acquisition processes for that company.

From 2009 through 2012, I worked for the Company as the Manager of Quantitative Analytics. In that role, I managed a group responsible for conducting long-term analyses of the costs and performance of Xcel's electric generating systems.

Prior to joining Xcel Energy in 2005, I was a PhD candidate in the Department of Applied Economics at the University of Minnesota where I studied energy related topics.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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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 STEVEN W. WISHART ON BEHALF OF PUBLIC SERVICE COMPANY OF COLORADO

I, Steven W. Wishart, 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 15th day of May, 2023.

Steve Wishart

Steven W. Wishart
Director of Regulatory Pricing and Analysis

Subscribed and sworn to before me this 15 day of May, 2023.

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

Notary Public

My Commission expires 07-29-2024