Exh. ZML-1T
Dockets UE-260005, UG-260006, and UE-260113
Witness: Ziad M. Lien

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-260005 & UG-260006 (Consolidated)**
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Accounting Order Authorizing the Deferred Accounting Treatment for FERC Interest Associated with Mandatory Transmission Network Upgrades**	**DOCKET UE-260113**

TESTIMONY OF

Ziad M. Lien

STAFF OF
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Embedded Cost of Service Model: Electric
Rate Spread/Rate Design: Electric

July 28, 2026

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Exh. ZML-15	PSE Response to UTC Staff DR No. 9

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ziad Lien, and my business address is 621 Woodland Square Loop SE, Lacey, WA 98503. My business mailing address is P.O. Box 47250, Olympia, WA 98504-7250. My email address is ziad.lien@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed as a Regulatory Analyst by the Washington Utilities and Transportation Commission (Commission) in the Energy Rates and Services section of the Regulatory Services Division.

Q. Would you please state your educational and professional background?

A. I graduated *magna cum laude* from the University of Colorado Boulder in 2023 with a Bachelor of Arts degree in Economics and a Bachelor of Arts degree in Environmental Studies. I am also currently pursuing a Master of Science degree in Applied Economics from the University of Maryland. Upon completing my undergraduate degree, I joined the Office of Administrative Litigation (OAL) at the Federal Energy Regulatory Commission (FERC) where I primarily focused on electric and gas rate case (GRC) filings. In September 2025, I joined the Washington Utilities and Transportation Commission's (Commission) Regulatory Services Division. Since joining Commission Staff (Staff), my responsibilities have included

the review and preparation of cost-of-service studies, statistical analyses, rate models, exhibits, and testimony related to investor-owned electric and natural gas utilities in Washington.

In addition to my work experience, I have completed the National Association of Regulatory Utility Commissioners (NARUC) Rate School. Additionally, I have completed an Energy Bar Association (EBA) training on transmission systems and Electric Utility Consultants, Inc. (EUCI) trainings on FERC Natural Gas Rate Case Filing processes and Ratemaking for Data Centers and Other Large Power Loads.

Q. Have you previously testified before the Commission?

A. Yes, I sponsored testimony on behalf of Commission Staff in *Washington Utilities and Transportation Commission v. Northwest Natural Gas Corporation*, Docket UG-250610 and *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*, Dockets UG-260007 & UE-260008.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose and scope of your testimony?

A. The purpose of my testimony is to examine the accuracy and reasonableness of Puget Sound Energy's (PSE or Company) as-filed electric cost-of-service (COS) study, as well as its proposed rate spread and rate design throughout the three-year multi-year

rate plan (MYRP). Accordingly, I evaluate, adjust, and comment on PSE's proposals relating to COS, rate spread, and rate design, based on the independent analysis I have undertaken on behalf of Staff.

Q. What are Staff's recommendations?

A. My COS study, rate spread, and rate design recommendations for PSE's electric services incorporate both my analysis and the recommendations of other Staff witnesses.

To start, Staff's COS study (Exh. ZML-2) reflects an adjustment to PSE's renewable future peak credit (RFPC) calculation to use RY1 cost assumptions, rather than a mix of 2026 and 2027 values, so that the RFPC better reflects the actual cost conditions PSE is expected to incur at the start of its MYRP. I also adopt the weather normalization methodology sponsored by Staff witness Dr. Halliday, which recalculates PSE's normal temperatures using 20 years of historical observed temperature data, rather than PSE's climate-adjusted approach.[1] Incorporating the adjustments above, together with Staff's recommended cost of capital (witness Parcell) and operation and maintenance expense adjustments (witness Kolesar), Staff's COS model results in a total revenue requirement at unity of approximately $3.081 billion, compared to PSE's proposed $3.164 billion.[2] Notwithstanding this change to the total revenue requirement, Staff's adjustments do not substantially alter PSE's COS indicated parity findings. With limited exception, most of PSE's rate

[1] Halliday, Exh. HSH-1T at 2:19:21.
[2] Lien, Exh. ZML-2, Tab "E-Summary of results," Column N, Line 8.

schedule parity ratios shift by less than one percentage point relative to the Company's as-filed results. Lastly, I recommend that the Commission direct PSE to file an updated COS study using the most recent consecutive 12 months of actual data available at the time of filing. This period should consist of the latter portion of RY1 and the available portion of RY2. PSE should file its updated study no later than six months before RY3 begins to ensure that the Commission and parties have sufficient time to review the resulting allocators and rate spread implications for the final year of the MYRP. An updated study would better capture changes in PSE's cost drivers and changes in customer usage patterns resulting from participation in PSE's time-of-use (TOU) schedules, as well as the interconnection of any large load and data center customers. Should the Commission reject my primary recommendation, I recommend that, at a minimum, PSE refresh the demand study component of its COS study using the same defined 12-month period and present the revised demand allocators to parties through a similar workshop process.

With respect to rate spread, I find PSE's proposed rate spread methodology to be reasonable, as it appropriately assigns increases at or near the system average to classes close to parity, while assigning proportionally lower increases to classes materially above parity and proportionally higher increases to classes materially below parity. Accordingly, I recommend that the Commission apply PSE's parity band structure to Staff's recommended net revenue change in base rates, which are as follows: a $683.86 million increase in RY1 (an approximate 50.63 percent decrease from PSE's as-filed $1,385.27 million), a $207.91 million increase in RY2 (an approximate 37.00 percent increase from PSE's as-filed $151.76 million), and a

$415.60 million increase in RY3 (an approximate 3.61 percent decrease from PSE's as-filed $431.16 million).[3]

Additionally, I recommend that the Commission direct PSE to refile an updated, recalculated COS study using a test period comprised of 12 months of RY1 and RY2 data and present the results to parties via workshop before the start of RY3, so that the Commission and parties can confirm whether the rate spread structure approved in this case continues to reflect cost causation principles as PSE's revenue requirement evolves over the course of the MYRP. Should the Commission reject my primary recommendation, I recommend, at a minimum, that PSE refresh the demand study component of its COS study using a test period comprised of 12 months of RY1 and RY2 load data, reflecting the impact of PSE's expanding TOU participation and any committed large loads, and present the results to parties through a similar workshop process.

Lastly, I examine PSE's rate design proposal. I recommend narrowing the pool of costs PSE proposes to recover through its residential and applicable general service basic charge, as prior Commission guidance demonstrates that basic charges should generally recover only a limited set of costs related to connecting and serving individual customers, regardless of usage. Additionally, I address PSE's proposed residential Tier 2 energy rate multiplier. I recommend that the Commission adopt PSE's proposed Tier 2 multiplier, as it still provides value in mitigating rate shock under Staff's recommended rates. Finally, I incorporate witness Dr. Halliday's

[3] Sorrells, Exh. SJS-1T at 3:2-4.

recommended changes to PSE's proposed TOU rates into Staff's ratemaking model (Exh. ZML-4). These modifications reflect witness Dr. Halliday's support for PSE's proposal to transition Schedules 307 and 327 from limited pilot participation to full-scale, voluntary residential TOU schedules, while incorporating witness Dr. Halliday's proposed adjustments to PSE's redesign of the applicable TOU time periods.[4]

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. I prepared Exhibits ZML-2 through ZML-15, listed above in the List of Exhibits.

III. COST ALLOCATION PRINCIPLES

Q. What is the purpose of a COS study in a ratemaking setting?

A. A utility's customer base includes a wide variety of rate schedules, which are served jointly despite being characterized by different needs. As such, the Commission relies on COS studies to functionalize, classify, and allocate costs as part of a broader effort to assign portions of the Company's proposed revenue requirement to various customer classes in accordance with each schedule's identified cost drivers.[5] Since under the Commission's guiding ratemaking principles "the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the

[4] Halliday, Exh. HSH-1T at 3:5-13.
[5] WAC 480-85-030(7).

service,"[6] the COS provides two key insights: (1) the revenue-to-cost ratio at present rates (i.e., each customer class's revenue at current rates divided by its respective revenue requirement), and (2) the parity ratio at present rates (i.e., each customer class's revenue-to-cost ratio divided by the system overall revenue-to-cost ratio). In other words, the COS establishes a benchmark for ratemaking principles by deliberately examining whether each customer class is contributing its fair share of the utility's total revenue requirement relative to the cost that it imposes on the utility's system, thereby giving the Commission an objective, class-specific basis for evaluating rate spread proposals and identifying which classes may be over- or under-contributing relative to cost.

Q. Should ratemaking be solely based on a utility's derived COS study results?

A. No. A utility's COS study should serve only as a benchmark for informing ratemaking decisions, which should instead rely on a holistic approach that accounts for policy considerations such as rate stability, gradualism, fairness, and economic conditions in the utility's service territory.[7] Indeed, while the Commission has consistently recognized the importance of COS study, it has also maintained that "allocation must depend on principled judgement rather than science."[8]

Q. Please provide a brief overview of the components used in PSE's COS studies.

[6] Lien, Exh. ZML-14 at 7.
[7] WAC 480-85-010(2).
[8] Lien, Exh. ZML-8 at 3.

A. PSE provides both electric and natural gas services in Washington State and accordingly, submits a separate COS study for each. The Company's electric COS study is presented in Exh. CTM-3 and is sponsored by witness Christopher T. Mickelson, and its natural gas COS study is presented in Exh. JDT-3, sponsored by witness John D. Taylor. Both studies conform to the Commission's COS rules, or where applicable, seek an exception from them to allocate each service's respective revenue requirement to individual rate schedules through three sequential steps:

(1) Functionalization;

(2) Classification; and

(3) Cost Allocation.[9]

A. Functionalization

Q. Examining the first step, what is the role of functionalization in a COS study?

A. Functionalization is the starting point in a COS study, where each cost incurred by the utility is traced back to the specific aspect of service that gives rise to said cost. For electric service, accounts are functionalized under Table 1 of WAC 480-85-060(3), where each is functionalized into the following categories:

(1) Generation;

(2) Transmission;

(3) Distribution;

[9] WAC 480-85-060(1)(a), (b).

(4) Customer; and

(5) Common.

Similarly, Table 3 of the same rule functionalizes accounts into the following categories for natural gas service:

(1) Production;

(2) Storage;

(3) Transmission;

(4) Distribution;

(5) Customer; and

(6) Common.

While the two frameworks are structurally similar, natural gas' functionalization categories include two gas-specific categories which do not appear in the electric COS: (1) production, and (2) storage. Production is largely analogous to electric generation, but gas storage has no direct standalone counterpart in the electric framework. Instead, electric storage related costs are functionalized according to each asset's operational role.

Q. Why are some accounts grouped under multiple functionalization categories?

A. A single FERC account may contain costs associated with assets or activities that perform numerous utility functions. As such, assigning the entire account to only one function could consequently misstate the true composition of costs contained in the account.

A common example of such an occurrence is found in FERC Account 403 – Depreciation Expense. Since Account 403 generally records the depreciation expense associated with the various classes of depreciable electric plant in service, the underlying account must be functionalized accordingly, with each portion following the function assigned to the associated plant.[10] In other words, the account's total balance must be divided among the functions represented by the underlying plant assets.

B. Classification

Q. Once costs have been functionalized, what is the next step in the COSS?

A. Once an account has been functionalized, it is then examined to identify the specific characteristics that gave rise to its costs. This process, known as classification, differs from functionalization in the sense that it asks what cost driver, such as customer count, energy usage, or system demand, gave rise to the cost.

Q. What classification categories are recognized by the Commission?

A. Classification methodologies among both electric and natural gas COS studies are known to comprise three main categories: (1) demand, (2) energy, and (3) customer. Each is described in greater detail, below.

[10] 18 C.F.R. § 101.

Q. Please describe demand costs, and how they are measured in a utility's COS study.

A. Demand costs, in both electric and natural gas COS studies, are driven by the capacity a utility must install and maintain to reliably serve its customers during periods of peak usage. This capacity requirement reflects the utility's obligation to provide "safe, adequate, and efficient service."[11] Because the utility's system must be designed to meet the highest-level demand expected to occur, rather than the average level of consumption (i.e., energy), these costs are generally characterized by the size and capability of the facilities needed to serve peak loads.

Q. Please describe energy costs.

A. Unlike demand costs, which are comprised of costs related to peak need assumptions, energy costs are based on the total quantity of energy supplied over a given period of time, regardless of the timing of the usage.[12] In practice, energy costs typically include costs that rise and fall with total throughput rather than with the system's peak capacity requirements. Since PSE provides both electric and natural gas services, these costs are measured using the volumetric unit applicable to each service: kilowatt hour (kWh) for electric service, and therms for natural gas service.

Q. Lastly, please describe customer costs.

[11] RCW 80.28.010(2).
[12] Lien, Exh. ZML-5 at 29.

A. Customer costs are the third classification method recognized by the Commission. This classification isolates a utility's costs that are driven by the number of customers connected to the system, rather than by how much energy a customer consumes (energy), or when they consume it (demand).[13] Customer costs typically include costs such as metering, billing, and customer service, and the portion of plant related investments attributable to connecting and serving individual customers, irrespective of usage characteristics.[14]

Q. How do these three classification categories work together in a utility's COSS and why is it important to distinguish between the classifications?

A. Taken together, demand, energy, and customer classifications provide the framework needed to examine functionalized costs and sort them according to why each cost arises, rather than merely where it arises. Providing a distinction between a given customer class's share of system peak demand, total energy usage, and total customer count is a critical component to determining cost responsibility as each class can differ substantially between rate schedules. As an example, a customer rate class with a flat, consistent usage profile may represent a large amount of total energy consumed while contributing little to system peak demand; whereas a class composed of many customers may be responsible for a large share of the system's peak demand while retaining a modest contribution to total energy.

[13] *Id.* at 31.
[14] WAC 480-85-060(3), Table 2.

Classifying costs in accordance with their true drivers, rather than treating all costs as interchangeable, ensures that the manner in which each cost is incurred is properly identified and preserved. As such, step 2 of a COS study, classification, is a critical step in determining whether each rate class is contributing its fair share to the revenue requirement relative to the cost each class imposes on the system.

C. Allocation

Q. Lastly, what does it mean for a utility to allocate its costs?

A. As part of the last step of a COS study, previously functionalized and classified costs are allocated to various rate schedules using specific allocation factors determined by each cost's functionalization and classification (i.e., energy, demand, or customer).[15]

WAC 480-85 prescribes the specific allocation methodologies that apply to each functionalized and classified cost.[16] For example, distribution substation costs that were previously functionalized as distribution are classified as demand and allocated to large customers through direct assignment based on each class's load ratio share of the substations serving it, while all other class's costs are allocated using an average of their relative shares of the distribution system's summer and winter coincident peaks.

In this way, allocation operationalizes the classification step outlined above: it is the mechanism by which the determination of a cost being demand-related,

[15] Lien, Exh. ZML-5 at 31.
[16] WAC 480-85-060(3), Tables 2 and 4.

energy-related, or customer-related is translated into a quantifiable assignment of dollars to each of PSE's rate schedules.

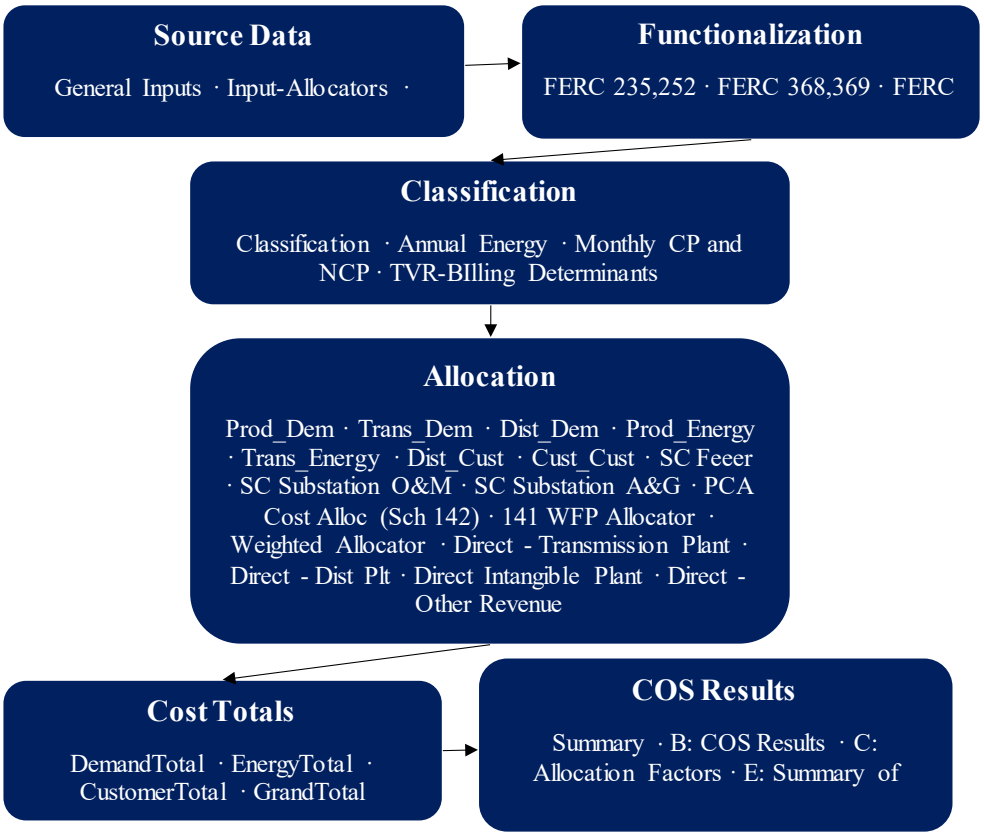
IV. ELECTRIC COST OF SERVICE STUDY

A. Overview

Q. Please provide a brief overview of how PSE organizes its electric COS study.

A. PSE complies with the cost-of-service requirements contained in WAC 480-85-060 by examining its FERC account balances as workbooks that trace costs to their function, sorting them by cost driver, and ultimately allocating them to individual rate schedules. PSE's electric COS, sponsored by witness Mickelson in Exh. CTM-3, is summarized below.

Figure 1: PSE's As-Filed Electric COS Study Flowchart



Notes and Sources:

[1] Mickelson, Workpaper CTM-3-E-COS-Model.

B. Demand Study

Q. Please describe the purpose of a demand study in a utility's cost-of-service.

A. Utilities perform demand studies as part of a COS study to determine each customer class's contribution to the utility's system-wide demand for capacity. After plant expenses have been functionalized, the demand study develops allocation factors used to assign demand-related costs to customer classes in accordance with cost

causation principles. These allocations may include coincident peak, non-coincident peak, or other demand allocators that have been determined to be appropriate for particular facilities or costs being allocated.

Accordingly, the demand study identifies (1) when the utility system experiences peak demand, (2) the size of those peaks, and (3) each customer class's relative contribution to them. The ensuing data is used to allocate the cost of the utility's capacity-related facilities, such as generation, transmission, and primary distribution plant costs, which are incurred to meet demand, to the customer classes which drive said costs. In such manner, a demand study is designed to interact with a utility's COS study to answer, "which customer class is driving the utility to build and maintain capacity-related infrastructure?"

Q. Is there a single uniform demand allocator applied to all demand classified costs?

A. No. Per WAC 480-85-060, demand-classified costs are allocated using several different peak-based measures, with the specific measure dependent on how the cost has been functionalized. As an example, FERC Account 356 – Overhead Conductors and Devices is functionalized as transmission, with its demand allocation following the system's single peak-demand hour for each of the twelve months of its study year (12 coincident peaks). In comparison, FERC Account 362 – Station Equipment is functionalized as distribution and allocated directly to large customers based on the load ratio share of the substations serving them, with all other classes using an

average of the relative share of the summer distribution system coincident peak and the relative share of the winter distribution system coincident peak.

Q. Has PSE included a new demand study for this rate case?

A. No. PSE's monthly coincident peak and non-coincident loads are retained from the same load research analysis and dataset used in its last electric GRC, Docket UE-240004.[17] PSE supports its usage of data based on a twelve month Test Year ending June 2023 by stating that "[t]he load research data and methodologies relied upon in this proceeding remain within the Commission's guideline that load studies not exceed five years in age and continue to be representative for cost-of-service purposes."

Q. Does Staff have concerns with PSE reusing its previous GRC demand study data?

A. Yes, Staff has concerns with the dataset PSE has selected for its demand study. PSE's use of data ending June 2023 may become increasingly unrepresentative over the course of PSE's proposed MYRP. While PSE asserts that its study follows WAC 480-85-050(2) by containing rate schedule usage data no older than five years, its proposed rate plan extends through 2029, where the data will be over six years removed from the Test Year used to develop PSE's rate schedule demand

[17] Lien, Exh. ZML-9.

allocators.[18] These concerns extend beyond the age of the data alone, and also stem from PSE's ongoing implementation of time-of-use rates.

Q. Would you please describe PSE's time-of-use rates?

A. Yes. In an effort to maintain safe, reliable, and affordable delivery of energy to customers under all conditions, while meeting its 2030 and 2045 clean energy targets, PSE was authorized to implement time-of-use (TOU) pilot rates in its 2022 GRC. These rates are part of a broader objective designed to lower peak demand and lower system costs by providing price signals that encourage customers to reduce usage during periods of peak demand.[19] From October 2023 through September 2025, PSE performed a two-year pilot period to evaluate TOU rate structures, customer incentives, and targeted communications across two winter and summer seasons for electric residential and small commercial customers.[20] Upon completion of its pilot evaluation period, PSE filed a tariff revision which, among other things, increased the customer participation limit and continued bill protections for participating customers.[21] These requests, later approved by the Commission, were designed to support TOU service for certain enrolled customers until PSE's full, residential TOU rates could be made available subject to approval in PSE's current

[18] *Id.,* Attachment B.
[19] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-220066, UG-220067 (consolidated) and UG-210918, Order 24/10, ¶ 291 (Dec. 22, 2022).
[20] Puget Sound Energy, *Pilot-Projects*, *available at* https://www.pse.com/en/pages/rates/GRC-Compliance/pilot-projects.
[21] *Petition of Puget Sound Energy to Approve Tariff Revisions Regarding Schedules 307, 317, 324, and 327 Related to Time-of-Use Pilot,* Docket UE-250725, Order 01 ¶ 4 (Dec. 11, 2025).

rate case, which, as described by Company witness Mickelson, is a TOU expansion that is largely driven by customer interest in greater control over their energy costs.[22]

Q. How could increased participation in PSE's TOU rates affect the accuracy and reasonableness of its present demand study?

A. PSE's TOU residential rates contained in Schedules 307 and 327 are designed to change when customers consume electricity. To the extent customers enrolled in these schedules respond as intended, three of the principle inputs behind a demand study are affected. First, residential class load shapes will flatten or shift, as on-peak consumption moves towards other hours. This is due to the rates offering reduced pricing during off-peak and super off-peak periods. Second, and most importantly for cost allocation purposes, PSE's residential class's contribution to the system coincident peak could materially change, as the stated objective of the TOU rates is to reduce demand during the hours that drive system peaks. Lastly, the widespread implementation of TOU rates may move individual residential customer non-coincident peaks over time, which could alter the allocation of some distribution demand related costs.[23] In this way, a demand study built on pre-implementation load data may overstate the contribution of PSE's residential class, especially in the later years of PSE's MYRP as PSE's TOU rate participation continues to grow.

Q. Are there other changed circumstances that warrant additional consideration?

[22] Mickelson, Exh. CTM-1T at 77:16-20.
[23] WAC 480-85-060(3), Table 2.

A. Yes. Between January 1, 2023, and March 1, 2026, PSE received inquiries from 27 potential large loads and data centers that may be located within the Company's electric service territory, with 10 of those remaining in study phase.[24] Although PSE does not consider potential load requests as probable until the customer commits to construction, several of these potential loads are substantial, as shown in Table 1, below.

Table 1: PSE's Prospective Large Load Customers (Jan. 1, 2023 through Mar. 31, 2026)

Line No.	Project[1] [A]	Type [B]	Requested Load (MW) [C]	Location (County) [D]	Request (Quarter) [E]
	Phase 2: Feasibility Assessment				
1	Potential Facility 14	Large Load	35	King	Q3 2024
2	Potential Facility 25	Data Center	65	Whatcom	Q3 2025
3	Potential Facility 26	Data Center	75	King	Q3 2025
4	Potential Facility 27	Large Load	177	King	Q3 2025
	Phase 3: Solutions Study				
5	Potential Facility 08	Data Center	70	King	Q1 2024
6	Potential Facility 10	Data Center	200	King	Q2 2024
7	Potential Facility 12	Large Load	50	King	Q3 2024
8	Potential Facility 20	Data Center	100	King	Q1 2025
9	Potential Facility 23	Data Center	80	Kittitas	Q2 2025
10	Potential Facility 24	Large Load	45	King	Q3 2025
	Phase 4: Request for Service; Proceed with Construction				
11	None	-	-	-	-

Notes and Sources
[1] Lien, Exh. ZML-10.

Q. Has PSE indicated whether it expects any of this large load interest to materialize?

[24] Lien, Exh. ZML-10.

A. Yes. In its response to UTC Staff DR No. 9, PSE indicated that it expects continued growth in large load and data center load within its service territory through 2030. Specifically, PSE's final F25 forecast projected an additional 20.5 megawatts (MW) of peak capacity and 5.4 average megawatts (aMW) of sales attributable to potential data center loads by 2030.[25] Although this forecast does not assert that every prospective customer load identified in Table 1 will materialize, it demonstrates that PSE itself anticipates a material level of data-center and large load growth during and shortly after PSE's proposed MYRP.

Q. How would the potential large loads described above affect the demand study underlying the Company's COS study?

A. As discussed above, a demand study is an integral component of a utility's COS study. It measures each rate schedule's relative contribution to the utility's system peak demand at both its coincident and noncoincident peaks, which is then used to assign production, transmission, and distribution-related demand costs. Because these allocators are derived from class load shapes, peak demands, and coincidence factors, any material change in the load characteristics of one customer class may change the allocation of demand-related costs among all of a utility's rate schedules, not merely the schedule under which the new load takes service. Consequently, the demand allocators derived from PSE's demand study may no longer accurately measure each class's relative responsibility for the demand-related costs PSE incurs

[25] Lien, Exh. ZML-15.

to satisfy its statutory obligation to provide safe, adequate, and efficient electric service.[26]

Q. How does the timing and probability of these loads matter to a demand study?

A. A demand study is designed to reflect load conditions that the utility believes to be reasonably representative of the period in which its results will be used. As reflected in Table 1, PSE's prospective large load customers remain in the feasibility or solutions study phases, with none formally requesting service. Accordingly, these loads cannot be treated on the same basis as committed load when developing PSE's demand study.

This creates an unavoidable forecast tension. Excluding speculative loads avoids mistakenly assigning costs based on customer demand that may never materialize, which would otherwise overstate future demand and prematurely assign a substantial amount of costs to rate schedules under which those customers are expected to take service. However, should loads of the magnitude shown in Table 1 interconnect during the MYRP, the existing demand study will no longer be representative of contributions to PSE's system peak, class peaks, or load shapes. Furthermore, the resulting COS study and rate spread would continue to rely on demand allocators developed from conditions that similarly no longer reflect actual cost causation.

[26] RCW 80.28.010(2).

Q. Understanding some of the challenges behind PSE's demand study, what is your recommendation?

A. PSE faces the challenge of maintaining a ratemaking methodology that produces fair, just, reasonable, and sufficient rates while customer usage patterns and system demand continue to evolve.[27] To address this concern, I recommend that the Commission direct PSE to refile an updated demand study as part of a larger, recalculated COS study.

The updated demand study should use the most recent consecutive 12 months of actual load data available at the time of filing and should consist of the latter portion of RY1 and the available portion of RY2. PSE should file the updated study no later than six months before RY3 begins to provide sufficient time for the Commission and parties to review the updated study and evaluate its implications on rate spread.

My concern is not that the Company's June 2023 test-year data was inappropriate when the demand study was first developed, but that the data grows less representative throughout the course of PSE's proposed MYRP. Refreshing the study using a defined 12-month period of actual RY1 and RY2 load data directly addresses the concerns discussed above, including more accurate changes to Schedules 307 and 327, and the interconnection of any large loads that have become sufficiently advanced or operational by the study period.

[27] RCW 80.28.010(1).

C. Renewable Future Peak Credit Calculation

Q. How has the Commission historically accepted classifying production costs?

A. As discussed in Section III, energy-related and demand-related costs are fundamentally different COS components. Energy-related production costs are incurred to serve load over time, whereas demand-related production costs are incurred to ensure the utility can meet customer needs during periods of peak usage. Recognizing the need to distinguish between these two categories, the Commission has historically accepted the use of a peak credit method to classify electric generation costs.[28]

Q. What is a renewable future peak credit calculation?

A. The renewable future peak credit (RFPC) is a calculation that determines what portion of a utility's generation plant costs should be classified as energy-related versus demand-related (i.e., peak capacity) within its COS study. Similar to traditional fossil fueled resources, renewable resources such as wind and solar provide both energy and capacity (demand) services. Accordingly, the RFPC isolates each component to ensure the underlying plant costs are appropriately classified.

This need for such calculation has grown through Washington's carbon-free generation requirements and system needs, where electric utilities in Washington are increasingly utilizing renewable resources (e.g., wind and solar) to transition away

[28] WAC 480-85-060(3), Table 2.

from traditional fossil-fueled generation resources (e.g., natural gas combustion turbines and coal plants).[29]

Q. Has the Commission previously weighed in on the use of the RFPC calculation in its cost-of-service studies?

A. Yes. Through its COS rulemaking completed in 2020, the Commission recognized that utilities are increasingly relying on renewable based generation to meet Washington energy policies, such as the Clean Energy Transformation Act (CETA).[30] Because the introduction of renewable resources is aimed to displace traditional fossil-fuel generation which has historically used the peak credit analysis, the Commission addressed how energy and demand-related components of renewable generation should be specifically identified in the COS study.

Through its 2020 rulemaking, the Commission embedded the RFPC methodology in a binding rule by requiring generation-based resources to be classified through the RFPC, with net power costs allocated on energy.[31] In its order, the Commission explained that this approach reflects how utilities plan around evolving technology and policy by drawing on the resource assumptions in a utility's integrated resource plan (IRP) rather than treating renewable capacity contribution as a static input.[32]

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[29] Wash. State Dept. of Ecology, *Climate Commitment Act*, *available at* https://ecology.wa.gov/air-climate/climate-commitment-act

[30] *In the Matter of Amending WAC 480-07-510 and Adopting Chapter 480-85 WAC*, Dockets UE-170002 & UG-170003, General Order R-599, ¶ 43 (July 7, 2020).

[31] WAC 480-85-060(3), Table 2.

[32] *In the Matter of Amending WAC 480-07-510 and Adopting Chapter 480-85 WAC*, Dockets UE-170002 & UG-170003, General Order R-599, ¶ 44.

Q. Please describe the assumptions used by PSE when calculating an RFPC.

A. PSE's method compares the cost of providing firm capacity through a four-hour lithium-ion battery storage resource, with the cost of producing renewable energy measured through wind resources using PSE's 2023 IRP and its 2027 cost assumptions.[33] In this framework, PSE treats its lithium-ion battery storage as demand-related, as it can contribute to capacity during peak conditions, but does not independently generate energy.[34] Wind costs, in comparison, are primarily treated as energy-related while recognizing that they also serve a limited demand-related component based on wind power's effective load-carrying capacity (i.e., what percent of the resource's installed capacity may be reliably used to meet peak demand, ELCC).[35] PSE's RFPC is the same study that was applied to its 2024 GRC but was modified to remove Inflation Reduction Act tax benefits which were eliminated under the One Big Beautiful Bill Act.[36] PSE explains the revision as necessary to accurately reflect the current cost environment and maintain methodology consistency with prior Commission direction.

Operating under these assumptions, PSE calculates that approximately 75.25 percent of its fixed generation costs should be classified as demand-related, with 24.75 percent of the remaining costs being classified as energy-related. PSE's updated calculation components represent a shift from its previously calculated roughly 70 percent demand and 30 percent energy-related fixed generation costs that

[33] Mickelson, Exh. CTM-1T, 25:14-18.
[34] *Id.* at 29:8-9.
[35] *Id.*at 29:10-11.
[36] *Id.* at 26:3-10.

were present in its prior GRC.[37] PSE's RFPC ratio and its various calculation inputs are summarized on Table 2, below.

Table 2: PSE, as-Filed Renewable Future Peak Credit Ratio

Line No.	Description [A]	Reference [B]	Results[1] [C]
	Lithium Ion Battery Storage		
1	Fixed Costs per KW	Levelized Cost ($/KW-yr)	$369.06
2	Battery Capacity Contribution		14.42%
3	Fixed Costs per KW w/ adjustment to match capacity of thermal peaker	Line 1 / Line 2 * (Thermal CCGT Winter ELCC - Wind ELCC)	$2,352.01
4	Storage Efficiency	Included in Levelization calculation	N/A
5	Total cost of Charging per KW-yr	Included in Levelization calculation	N/A
6	Total Cost per MW	Line 3 X 1000	$2,352,006.36
	Wind		
7	Fixed Cost per KW	Levelized Cost ($/KW-yr)	$455.24
8	Fixed Costs per KW w/ adjustment to match output of Combined Cycle	CC CF / Wind CF	1.74
9	Total Fixed Costs per KW	Line 7 X Line 8	$791.13
10	Demand Related Cost @ 2% Capacity Contribution per KW	Line 9 X Wind ELCC @ 2%	$17.56
11	Total Energy Related Cost	Line 9 - Line 10	$773.57
12	Fixed Cost per MW	Line 11 X 1000	$773,573.78
13	PTC Rate Assumption	Updated to reflect One Big Beautiful Bill Act	0
14	**Demand Component**	**Line 6 / (Line 6 + Line 12)**	**75.25%**
15	**Energy Component**	**100% - Line 14**	**24.75%**

Notes and Sources

[1] Mickelson, Workpaper CTM-3-E-Renewable-Peak-Credit, Tab "Peak Credit".

Q. Do you propose any adjustments to PSE's RFPC ratio?

A. Yes. I propose adjusting PSE's RFPC to reflect: (1) 2027 RY1 conditions for the ratio's input values, (2) the true reported value of Wind's fixed O&M costs, (3) PSE's actual federal income tax rate under the Tax Cuts and Jobs Act (TCJA), and (4) modifying PSE's capital structure and weighted average cost of capital to reflect

[37] *Id.* at 33:17-19.

Staff's recommendation.[38] As discussed in greater detail below, each of these adjustments is aimed at ensuring PSE's RFPC is best representative of its relevant energy and demand related fixed generation costs.

Q. Why is it important for PSE's RFPC to reflect RY1 conditions?

A. The purpose of the RFPC is to provide a reasonable estimation of a utility's demand and energy-based values of future renewable resources so that fixed generation costs are appropriately classified in its COS study.[39] Since these classified values will ultimately affect the allocation of costs among customer classes and serve as the basis for rates for PSE's RY1 and onwards, the underlying assumptions used to compute the RFPC should correspond accordingly. In other words, using assumptions that do not reflect RY1 conditions risks misclassifying generation costs and may affect the allocation of costs among PSE's rate schedules.

Q. Does PSE consistently use a 2027 cost assumption?

A. No. Although PSE labels the relevant inputs as 2027-dollar assumptions, its supporting calculation model carries 2026 values on two occasions:

(1) Battery Fixed O&M costs;[40] and

(2) Wind Transmission costs.[41]

[38] Tax Policy Center, *How Did the Tax Cuts and Jobs Act Change Business Taxes?*, *available at* https://taxpolicycenter.org/briefing-book/how-did-tax-cuts-and-jobs-act-change-business-taxes.
[39] WAC 480-85-060(3), Table 2.
[40] Mickelson, Workpaper CTM-3-E-Renewable-Peak-Credit, Tab "Levelize FC," Column E, Line 14.
[41] *Id.*, Tab "Levelize FC," Column F, Line 15.

Because the RFPC is intended to support the classification of generation costs for rates that will first become effective in RY1, it is appropriate for these inputs to consistently reflect 2027 conditions.

Q. How do you address these inconsistencies?

A. I adjust both input values to reflect PSE's 2027 cost assumptions. Accordingly, PSE's fixed O&M battery plant assumption is adjusted from $51.70 per kW-year to $51.48, representing a 22-cent (0.43 percent) reduction.[42] Similarly, I update PSE's wind transmission costs from $66.75 per kW-year to $71.34, which is an approximately $4.59 (6.88 percent) increase.[43]

Q. What is the issue with PSE's fixed O&M input for wind?

A. PSE's fixed O&M input for wind does not reference the workbook's fixed operation and maintenance assumptions, but rather pulls values from the model's fixed transmission costs by summing Bonneville Power Administration (BPA) and non-BPA transmission costs associated with the selected wind resource.[44] Since PSE separately includes a wind transmission input elsewhere in the RFPC calculation, the workbook appears to include wind transmission costs as two separate inputs, thereby increasing its relevant fixed costs per kW.

[42] Lien, Exh. ZML-11, Tab "Levelize FC," Column E, Line 14.
[43] *Id.,* Tab "Levelize FC," Column F, Line 15.
[44] Mickelson, Workpaper CTM-3-E-Renewable-Peak-Credit, Tab "Levelize FC," Column F, Line 14.

Q. What adjustment does Staff propose to PSE's fixed O&M input related to wind?

A. I recommend adjusting PSE's fixed O&M input for its wind resources to reflect cost inputs sourced from its fixed O&M cost worksheet. Doing so reduces PSE's fixed O&M per kW-year for its wind costs, from $71.34 to $32.01, approximately a $39.33 (55.13 percent) decrease. [45]

Q. Does Staff have additional issues with respect to PSE's RFPC calculation?

A. Yes. PSE's fixed charge rate calculation continues to use a hardcoded 35 percent federal corporate income tax rate assumption when calculating certain tax-related components.[46] The 2017 Tax Cuts and Jobs Act (TCJA) lowered the federal corporate income tax rate from 35 to 21 percent, effective for tax years beginning after December 31, 2017. As a result, 21 percent has been the applicable federal corporate income tax rate since 2018, and the 35 percent tax rate is no longer in effect. Specifically, PSE's deferred tax and tax benefit of interest calculation continues to rely on a 35 percent input, despite PSE using a stated 21 percent federal corporate income tax rate assumption in all other parts of its workbook.[47]

Q. What does Staff recommend regarding the use of an incorrect tax rate?

[45] Lien, Exh. ZML-11, Tab "FOM," Column F, Line 14.
[46] Tax Policy Center, *How Did the Tax Cuts and Jobs Act Change Business Taxes?*, *available at* https://taxpolicycenter.org/briefing-book/how-did-tax-cuts-and-jobs-act-change-business-taxes.
[47] Mickelson, Workpaper CTM-3-E-Renewable-Peak-Credit, Tab "Tax Depreciation," Line 106.

A. I update PSE's deferred tax and tax benefit of interest calculations to use the workbook's stated 21 percent tax assumption rather than the hard-coded 35 percent value. This adjustment better aligns PSE's fixed charge rate calculation with its stated financial assumptions and ensures that tax-related components are calculated using a consistent corporate federal income tax rate.[48] PSE's stated 21 percent federal corporate income tax assumption is not contested but instead applied consistently throughout the affected fixed charge rate calculations.

Q. Lastly, what is Staff's adjustment to PSE's RFPC capital structure?

A. PSE's RFPC capital structure is modified to reflect a 9.63 percent return on equity (ROE) and a 4.81 percent weighted average cost of capital (WACC), as recommended by Staff Witness Parcell.[49] Updating these inputs ultimately affects the fixed charge rate used to annualize capital cost for both battery and wind capital costs. Since PSE's proposed demand component is approximately 75.25 percent, the net impact of this adjustment will lower the fixed charge rate of the demand component (battery storage) to a higher degree due to its more capital-cost driven components.

Q. What is the impact of Staff's adjustments?

A. A summary of the adjusted input factors is displayed in Table 3, below. Overall, the net impact results in a 2.33 percent increase in the demand-based component, and a

[48] Lien, Exh. ZML-11, Tab "Tax Depreciation," Line 106 and Tab "Cash Flow Statement (Results)" Line 7.
[49] Parcell, Exh. DCP-1T at 3:4-14.

7.07 percent decrease in the energy-based component. The percent change of each input is found on Column E.

Table 3: As-Filed versus Staff Adjusted Renewable Future Peak Credit Ratio

Line No.	Description [A]	Reference [B]	PSE, as-Filed[1] [C]	Staff, as-Adjusted[2] [D]	% Change [E]
	Lithium Ion Battery Storage				
1	Fixed Costs per KW	Levelized Cost ($/KW-yr)	$369.06	$365.77	-0.89%
2	Battery Capacity Contribution		14.42%	14.42%	-0.02%
3	Fixed Costs per KW w/ adjustment to match capacity of thermal peaker	Line 1 / Line 2 * (Thermal CCGT Winter ELCC - Wind ELCC)	$2,352.01	$2,311.05	-1.74%
4	Storage Efficiency	Included in Levelization calculation	N/A	N/A	
5	Total cost of Charging per KW-yr	Included in Levelization calculation	N/A	N/A	
6	Total Cost per MW	Line 3 X 1000	$2,352,006.36	$2,311,046.30	-1.74%
	Wind				
7	Fixed Cost per KW	Levelized Cost ($/KW-yr)	$455.24	$409.75	-9.99%
8	Fixed Costs per KW w/ adjustment to match output of Combined Cycle	CC CF / Wind CF	1.738	1.738	0.00%
9	Total Fixed Costs per KW	Line 7 X Line 8	$791.13	$712.08	-9.99%
10	Demand Related Cost @ 2% Capacity Contribution per KW	Line 9 X Wind ELCC @ 2%	$17.56	$15.80	-10.01%
11	Total Energy Related Cost	Line 9 - Line 10	$773.57	$696.28	-9.99%
12	Fixed Cost per MW	Line 11 X 1000	$773,573.78	$696,278.52	-9.99%
13	PTC Rate Assumption	Updated to reflect One Big Beautiful Bill Act	0	0	
14	**Demand Component**	**Line 6 / (Line 6 + Line 12)**	**75.25%**	**77.00%**	**2.33%**
15	**Energy Component**	**100% - Line 14**	**24.75%**	**23.00%**	**-7.07%**

Notes and Sources
[1] Mickelson, Workpaper CTM-3-E-Renewable-Peak-Credit, Tab "Peak Credit".
[2] Lien, Exh. ZML-11, Tab "Peak Credit".

Overall, a higher demand-based component and a lower energy-based component indicates that a larger share of fixed generation costs is being classified as demand-based needs. To break out this concept formulaically, we may utilize PSE's RFPC energy and demand percentages (cost per MW), which may be generally understood as:

$$RFPC\ Demand\ (\%) = \frac{Battery\ Capacity\ Costs}{Battery\ Capacity\ Costss + Wind\ Energy\ Related\ Costs}$$

and

$$RFPC\ Energy\ (\%) = \frac{Wind\ Energy\ Related\ Costs}{Battery\ Capacity\ Costs + Wind\ Energy\ Related\ Costs}$$

Although these adjustments reduce both the demand-related and energy-related cost inputs used in the RFPC calculation, the energy-related wind costs decrease by a larger share.[50] Since the RFPC demand component is calculated as demand-related costs divided by the sum of demand-related and energy-related costs (as seen above), the relative share of demand-related costs will increase when the energy-related portion of the denominator declines to a higher degree. Simply stated, my adjustments to PSE's RFPC do not increase demand-related costs in absolute terms; rather, it increases the percentage of fixed generation costs classified as demand-related because energy-related costs now consist of a smaller share of the total RFPC costs. From a COS perspective, this results in a larger portion of fixed generation costs being allocated through demand allocators and a smaller portion being allocated through energy allocators. This shift places relatively more cost responsibility on customers with larger coincident peak demands and relatively less cost responsibility on customers with higher load factors and more level energy consumption.

D. Weather Normalized Load

Q. What is the role of a weather normalization adjustment in a COS study.

A. A weather normalization adjustment removes the effect of an abnormal weather pattern from the utility's test year loads and revenues so that the cost-of-service

[50] Lien, Exh. ZML-11, Tab "Peak Credit."

reflects largely standard weather conditions. As detailed in Section III, a COS study is designed to allocate costs among customer classes, which may also include billing determinants and pro forma revenue components that are sensitive to weather. While the system-level weather normalization adjustment addresses overall test year usage per customer (UPC) and the resulting revenue requirement, the COS study requires this same normalization principle to be applied at the class level, since different classes can exhibit different weather sensitivities. An abnormal weather event, such as an unusually cold or warm test year would otherwise distort each class's usage and revenue and therefore affect its cost responsibility. By including a weather normalization adjustment, utilities correct for these abnormalities and ensure that allocation factors, class revenues, and the resulting COS derived parity ratios reflect expected conditions.

Q. Does Staff propose any changes to PSE's weather normalization methodology?

A. Yes. As described in greater detail by Staff witness Dr. Halliday, Staff is sponsoring an adjustment to PSE's weather normalization methodology which re-calculates PSE's normal temperatures using 20 years of historical observed temperature data, from 2005 through 2024 as recorded at Seattle-Tacoma International Airport.[51]

Q. Does PSE recalculate its COS study using this methodology?

[51] Halliday, Exh. HSH-1T at 14:5-14.

A. Yes. As part of PSE's response to UTC Staff DR No. 220, PSE recalculated its weather normalization adjustment contained in its electric COS study using Staff's requested methodology.[52] For ease of reference, PSE includes the delta values between the originally filed adjustment and the recalculated method to demonstrate the differences in test year proposed revenue from rates and parity ratios by rate class.[53]

Q. What impact does PSE's recalculated weather normalization adjustment have on PSE's COS study?

A. PSE's weather normalization methodology relies on climate-adjusted temperature data rather than historical actuals, which has the effect of prematurely incorporating forecasted warming into the test year and understating expected volumes and revenues.[54] Incorporating Staff's adjustment into PSE's COS study increases total test year volumes by 207.8 million kWh and total test year pro forma revenues by $29.3 million.[55] This shift flows through the model's revenue-responsibility calculations, producing small changes across most of PSE's rate schedules.

[52] Lien, Exh. ZML-12, Attachment C.
[53] *Id.*, Attachment C, Tab "E-Summary of Results," Lines 28 and 31.
[54] Halliday, Exh. HSH-1T at 17:6-9
[55] Lien, Exh. ZML-12, Attachment C, Tab "E-Summary of Results," Lines 28 and 31.

E. Revenue Requirement Adjustments

Q. Does Staff incorporate any additional adjustments when evaluating the COS results and parity ratios?

A. Yes. In addition to modifications to weather normalization, I incorporate adjustments to PSE's revenue requirement that reflect Staff's recommended cost of capital (as discussed by witness Parcell) and O&M (as discussed by witness Kolesar).

Q. What is the overall effect of Staff's revenue requirement adjustments on PSE's COS results?

A. Staff's adjustments materially reduce the total revenue required at unity. PSE's COS study calculates a total revenue requirement at unity of approximately $3.164 billion.[56] Staff's model calculates approximately $3.081 billion, a reduction of approximately $83 million. Together, these changes convert PSE's calculated system net income deficiency of approximately $50.6 million into a system net income sufficiency of approximately $33.4 million.[57]

Q. Do Staff's adjustments affect all customer classes equally?

A. No. Because PSE's electric COS study functionalizes, classifies, and allocates costs in a manner that is consistent with WAC 480-85-060, no two rate schedules are assigned cost responsibility through the same combination of allocation factors. As

[56] Mickelson, Exh. CTM-3, Tab "E-Summary of Results," Column N, Line 8.
[57] Lien, Exh. ZML-2, Tab "E-Summary of Results," Column N, Line 8.

discussed in Section III, some costs are allocated based on each class's share of system demand, others on share of total energy usage, and others on their number of customers; all of which can differ substantially from each other. As a result, an adjustment to any single cost input in the revenue requirement does not flow through the COS uniformly, meaning each rate schedule's COS indicated parity ratio is affected differently.

For example, a reduction in PSE's proposed ROE lowers the overall rate of return applied to rate base, which is presently modeled at a uniform 8.09 percent across every function in RY1.[58] Because this rate is applied uniformly, a lower ROE will reduce the dollar return associated with each rate schedule, but only in direct proportion to how PSE's rate base has already been classified and allocated.

Similarly, PSE's temperature adjusted annual energy allocation varies by rate schedule, as each customer class's usage carries its own weather sensitivity, when applicable.[59] As a result, recalculating the weather normalization adjustment does not shift every schedule's kWh by the same amount, which results in unequal changes to each schedule's share of energy-related costs.

F. Electric Cost of Service Insights and Outcomes

Q. What are the impacts of Staff's adjustments on PSE's COS study results?

[58] Mickelson, Exh. CTM-3, Tab "E-Summary of Results," Line 3.
[59] Halliday, Exh. HSH-1T at 4:9-14.

A. Staff's cumulative adjustments materially change PSE's electric COS study results at present rates, as shown in Table 4, below. On a total system basis, PSE's as-filed revenue-to-cost ratio increases by approximately 3.65 percent, from 0.9786 to 1.0143 under Staff's adjusted COS study.[60] Consistent with this system-wide increase, the adjusted revenue-to-cost ratios at present rates increase across all rate schedules with billed load, with the largest measured effect occurring for PSE's Choice/Retail Wheeling schedule (approximately 7.90 percent), followed by Special Contract (approximately 4.03 percent), and Residential Service (approximately 3.91 percent).

Table 4: As-Filed versus Staff Adjusted Electric Revenue-to-Cost and Parity Ratios at Present Rates

		Revenue-to-Cost Ratio at Present Rates			Parity Ratio at Present Rates		
Line No.	Rate Schedule [A]	PSE, as-Filed[1] [B]	Staff, as-Adjusted[2] [C]	% Change [D]	PSE, as-Filed [E]	Staff, as-Adjusted [F]	% Change [G]
1	Res Svc	0.9881	1.0267	3.91%	1.0097	1.0122	0.25%
2	Sec Svc 24	0.9836	1.0163	3.33%	1.0051	1.0020	-0.31%
3	Sec Svc 25/29/7A	0.9518	0.9832	3.30%	0.9726	0.9693	-0.34%
4	Sec Svc 26/26P	0.9819	1.0136	3.23%	1.0034	0.9993	-0.41%
5	Priv Svc 31	0.9391	0.9689	3.17%	0.9596	0.9552	-0.46%
6	Priv Svc 35	0.0000	0.0000		0.0000	0.0000	
7	Priv Svc 43	0.8566	0.8891	3.80%	0.8753	0.8766	0.14%
8	Special Contract	1.0436	1.0856	4.03%	1.0664	1.0703	0.36%
9	High Volt 49	1.0127	1.0423	2.92%	1.0348	1.0276	-0.70%
10	Choice / Retail Wheeling	0.7620	0.8222	7.90%	0.7787	0.8106	4.09%
11	Lighting 50-59	0.9248	0.9497	2.69%	0.9450	0.9363	-0.92%
12	Firm Resale	1.1430	1.1614	1.61%	1.1680	1.1450	-1.97%
13	**Total**	**0.9786**	**1.0143**		**1.0000**	**1.0000**	

Notes and Sources

[1] Mickelson, Exh. CTM-3, Tab "E-Summary of Results".

[2] Lien, Exh. ZML-2, Tab "E-Summary of Results".

[60] Lien, Exh. ZML-2, Tab "E-Summary of Results," Column N, Line 13.

However, the parity ratios demonstrate that Staff's adjustments do not affect all classes equally with respect to improving relative cost responsibility trends. Newly recalculated parity ratios demonstrate that several classes move further below parity under Staff's adjusted study. For instance, PSE's Street Lighting Service schedule declines from 0.9450 to 0.9363. Overall, Staff's adjustments modestly shift PSE's relative class cost indications, but, as will be discussed in Section V, do not undermine the reasonableness of PSE's proposed rate spread methodology.

Q. Do you have any additional recommendations?

A. Yes. In my discussion of PSE's demand study, I recommended that the Commission direct PSE to refile an updated demand study as part of a larger, recalculated COS study. I renew and expand on that recommendation here.

A COS study is largely built on data from the utility's test year, which means the cost allocation factors it produces, and the following rate spread decisions, reflect a snapshot of the utility's system at one point in time. In a MYRP, that snapshot becomes increasingly outdated, yet it continues to dictate rate spread across each year of the utility's MYRP, even as the utility's revenue requirement, load shapes, and cost drivers evolve. In other words, the longer a utility's MYRP, the more likely it becomes that the allocations underlying the original COS study no longer accurately reflect the utility's underlying cost relationships and customer usage patterns. As an example, if PSE experiences a material increase in its TOU program enrollment, or adds one or more large load customers, the demand allocators embedded in its COS study will no longer capture those customers' actual

contribution to PSE's system peak or its usage patterns. Consequently, costs could continue to be assigned to rate classes based on a load relationship that no longer exists, even though the Commission's approved rate spread was reasonable when it was adopted.

To mitigate this concern, Staff recommends that the Commission direct PSE to file a recalculated COS study no later than six months before the start of RY3. The recalculated study should use the most recent consecutive 12 months of actual data available at the time of filing, which should consist of the later portion of RY1 and the available portion of RY2. Defining the study period as such avoids the timing problems associated with requiring complete actual data for both RY1 and RY2 while still providing insight into how cost responsibility is progressing among rate classes as the MYRP unfolds.

Staff recommends the Commission require PSE to present the recalculated COS results through a workshop process sufficiently before RY3 takes effect. This would allow the Commission and parties to evaluate whether the rate spread structure approved in this proceeding continues to reflect cost-causation principles, or whether modifications should be considered for RY3. Should the Commission reject this primary recommendation, Staff recommends, at a minimum, PSE refresh the demand study component of its COS study using the same defined 12-month period of actual RY1 and RY2 load data. Similarly, PSE should then present the revised demand study allocators to all parties through a workshop so that the Commission and parties can evaluate whether changes in class load characteristics necessitate corresponding adjustments to the Company's RY3 rate spread.

V. RATE SPREAD

A. Overview

Q. What is rate spread?

A. Rate spread is the methodology in which a utility allocates its authorized revenue requirement among its customer classes, such as its residential, commercial, and industrial customers. It is typically guided by each class's respective COS indicated parity ratio, which is said to be the class's revenue at current rates divided by the revenue requirement (revenue-to-cost ratio) divided by the system's revenue-to-cost ratio.[61]

Q. Should a COS study be the only consideration when assigning rate spread?

A. No. As discussed in Section III, while a COS study may provide insight into a fair distribution of costs, "allocation must depend on principled judgement rather than science."[62] As a result, a COS study should be used as no more than a benchmark for informing rate spread, which should additionally balance goals such conservation signals, differential risks, economic efficiencies, fairness, equity, and gradualism.[63]

[61] WAC 480-85-030.
[62] Lien, Exh. ZML-8 at 3.
[63] *Id.* at 5-7.

B. Electric Rate Spread

Q. What is Staff's recommended electric service incremental revenue requirement?

A. As presented in Staff witness Sorrells' revenue requirement model, Staff recommends that the Commission approve the following incremental revenue increases to electric base rates over the course of PSE's MYRP:

(1) $683.86 million in RY1;

(2) $207.91 million in RY2; and

(3) $415.60 million in RY3.[64]

By comparison, PSE proposed the following net revenue changes to electric base rates in its three-year MYRP:

(1) $1,385.27 million in RY1;

(2) $151.76 million in RY2; and

(3) $431.16 million in RY3.[65]

Q. What does PSE propose regarding its electric rate spread?

A. Once an appropriate incremental revenue requirement for each rate year has been determined, that revenue requirement must be distributed among PSE's individual rate schedules. PSE's rate spread is designed to gradually align each customer class's revenues more closely with the results of its COS study while avoiding sharp

[64] Sorrells, Exh. SJS-4, Tab "Summary", Line 76.
[65] Free, Exh. SEF-4, Tab "Summary", Line 76.

changes to class-specific rates.[66] As a result, the Company designs a framework where customer classes close to parity receive increases approximately equal to the system average, while classes materially above parity receive proportionally lower-than-average increases and classes materially below parity receive proportionally higher increases. PSE's proposal is shown on Table 5, below:

Table 5: As-Filed Electric Parity Bands

Line No.	Parity Ratio [A]	% of Uniform Change [1] [B]
1	1.50 < x	150%
2	1.20 < x < 1.50	75%
3	1.05 < x < 1.20	90%
4	0.95 < x < 1.05	100%
5	0.80 < x < 0.95	110%
6	0.50 < x < 0.80	125%
7	x < 0.50	150%

Notes and Sources
[1] Mickelson, Exh. CTM-1T at 39:8-21.

Q. How does PSE's rate spread apply to each of its existing rate schedules?

A. PSE's proposed rate spread methodology is summarized in Table 6, below. Notably, it does not include Retail Wheeling (Schedule 449/459), Special Contract (Schedule SC), or Firm Resale (Schedule 5) customers, who are treated as unique customer classes, with costs directly established from their respective COS results. Therefore,

[66] Mickelson, Exh. CTM-1T at 38-39.

these schedules do not see PSE's parity-banding approach, as is used for the Company's traditional customer classes.[67]

Table 6: As-Filed Electric Rate Spread Methodology

Line No.	Description [A]	Rate Schedule [B]	Parity Ratio [1] [C]	% of Uniform Change [2] [D]
1	Residential Service	7/307/327	1.00970	100%
2	General Service (< 51 kW)	8/24	1.00510	100%
3	General Service (51 - 350 kW)	7A/11/25/29	0.97260	100%
4	General Service (> 350 kW)	12/26	1.00340	100%
5	Primary Service, General	10/31	0.95960	100%
6	Primary Service, Schools	43	0.87530	110%
7	High Voltage Service	49	1.03480	100%
8	Street Lighting Service	3, 50-59	0.94500	110%

Notes and Sources
[1] Mickelson, Exh. CTM-3, Tab "E-Summary of Results".
[2] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "Exh. CTM-Rate Spread".

Q. Is PSE's proposed rate spread applied consistently throughout the course of its three-year MYRP?

A. Yes. PSE applies the same rate spread methodology in each year of its three-year MYRP. Each rate schedule's parity ratio, as derived from PSE's COS study, is held constant and applied uniformly across all three rate years. This results in each rate schedule seeing the same parity ratio indicated percent of the average increase, as exhibited in Table 6, above, throughout all years of PSE's MYRP.[68]

[67] *Id.* at 40:8-11.
[68] Mickelson, PSE-WP-CTM-4, Tab "Exh. CTM-Rate Spread."

Q. Does Staff recommend any changes with respect to PSE's rate spread over the course of the MYRP?

A. Yes. Consistent with the recommendation provided in Section IV, Staff recommends the Commission direct PSE to reevaluate its RY3 rate spread based on a newly recalculated COS study. PSE should file such study no later than six months before RY3 begins, using the most recent consecutive 12 months of actual data available at the time of filing. The study period should consist of the later portion of RY1 and the available portion of RY2.

An updated study would demonstrate whether each class is moving towards or away from parity as the composition of PSE's revenue requirement, customer usage patterns, and cost drivers evolves over the course of the MYRP. Staff recommends the Commission require PSE to present the recalculated COS results and any resulting RY3 rate spread proposal to the parties via workshop process to ensure that the proposal can be reviewed before RY3 takes effect.

This recommendation is consistent with PSE's stated ratemaking objectives by: (1) offering and providing revenue and rate stability and predictability, (2) reflecting the actual costs of providing service, (3) embedding fairness in rate structures, and (4) providing accurate price signals to customers.[69] The proposal review would help determine whether PSE's rate schedules are making reasonable progress toward parity, subject to the Company's approved parity banding approach,

[69] Mickelson, Exh. CTM-1T at 43-44.

while accounting for changes in the composition of PSE's revenue requirement and the relative cost responsibility of each of its customer classes.

VI. RATE DESIGN

A. Overview

Q. What is Staff's analysis regarding rate design?

A. In this section, I address a portion of PSE's customer charge and energy rate design components. I begin by describing the components of a customer bill, then examine PSE's proposed changes to its basic charge against two benchmarks: the Commission's Order 08 in PacifiCorp's 2014 GRC[70] and economic principles drawn from *The Economics of Public Utility Regulation*.[71] Using those benchmarks, I conduct an independent analysis of which FERC accounts are appropriate for recovery through PSE's basic charge, which in turn supports my proposed alternative basic charge.

Next, I address PSE's proposed TOU rate design for residential Schedules 307 and 327, where I adopt witness Dr. Halliday's recommended adjustments to better align the schedules with the periods actually tested during the pilot and to avoid an overly long evening peak window into Staff's rate model.[72]

[70] *See generally Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Company*, Dockets UE-140762, UE-140617, UE-131384, UE-140094 Order 08 (Mar. 25, 2015) ("2015 PacifiCorp Order").
[71] Lien, Exh. ZML-7.
[72] Halliday, Exh. HSH-1T at 3:5-13.

Lastly, I examine PSE's proposed residential Tier 2 multiplier, which governs how PSE's overall proposed rate increase is allocated between Tier 1 and Tier 2 usage under the Company's existing two-tier residential rate structure throughout its MYRP. I provide support for my recommendation that the Commission adopt PSE's proposed Tier 2 multipliers through the MYRP under Staff's proposed revenue requirements. I also address PSE's proposed structural alternatives to its residential tier design, which the Company declined to pursue in this proceeding, and explain why I support addressing and examining such alternatives in a future collaborative workshop rather than in this proceeding.

Q. What are the components of a customer's bill?

A. A customer taking service on a utility's system will generally incur up to three separate categories of charges, depending on the customer's rate schedule. To begin, a customer may incur a basic charge, which is intended to cover a limited set of customer-related costs that do not vary with usage. A customer may also incur a demand charge, which is designed to recover costs associated with maintaining sufficient system capacity to meet peak usage requirements. Lastly, a customer will incur an energy charge, which is an oftentimes tiered volumetric charge based on the amount of kWh or therms (energy) consumed.

Q. Which of the three individual charges do you address in your testimony?

A. My testimony addresses both the basic charge and the energy charge components of a customer's bill. Section VI addresses PSE's proposed basic charge, while Section

VII examines PSE's energy rate, which ties directly to Staff's adjusted revenue requirement. My recommendations offer meaningful progress towards "fair, just, reasonable and sufficient rates" while balancing policy considerations, such as rate shock and excessive rate case complexity.[73]

A. Electric Basic Charge

Q. Please summarize the role of a basic charge.

A. A utility employs a fixed, monthly charge, commonly referred to as a basic charge, as a means to recover a limited set of customer-related costs that do not vary with usage. Typically, these costs are associated with items related to metering, billing, and services. The basic charge helps ensure the stable recovery of costs associated with providing service to a customer, even when consumption fluctuates monthly or seasonally.[74] The Commission has previously recognized the basic charge as a distinct and important component of rate design, while emphasizing that it should remain limited in scope and change only gradually between rate cases.[75]

Q. At a high level, how does PSE frame its rate design objectives in this proceeding?

A. PSE witness Mickelson states that the Company develops rates according to a set of seven measures which align with the guidelines established by utility rate principles

[73] RCW 80.28.010(1).
[74] Lien, Exh. ZML-6 at 261.
[75] 2015 PacifiCorp Order at 91 ¶ 216.

found in the *Principles of Public Utility Rates* by James C. Bonbright et. al.: (1) recovering the Company's overall revenue requirement, (2) providing revenue stability and predictability, (3) offering rate stability and predictability, (4) reflecting the actual costs of providing service, (5) embedding fairness in rate structures, (6) providing accurate price signals to customers, and (7) maintaining simplicity and ease of understanding.[76] As discussed below, PSE's basic charge increase is presented as one component of a broader effort to realign each of the Company's bill components with its cost-of-service indicated results.

Q. What is PSE's main concern with its current basic charges?

A. PSE cites to Order 08 from its 2011 GRC[77] to emphasize that its residential basic charge has remained largely unchanged for nearly 15 years.[78] PSE contends that its existing basic charges no longer reflect the true nature of fixed costs incurred to provide and maintain grid access, which is a key cost component that does not vary with customer usage. Accordingly, increasing the basic charge towards each rate class's appropriate customer-related costs serves two main functions: (1) reducing intra-class cross-subsidization by preventing high-usage customers from paying fixed costs unrelated to their consumption, and (2) aligning the basic charge with cost-causation principles, which PSE contends will help customers understand that the charge is simply tied to the cost of maintaining access to the electric system. [79]

[76] Mickelson, Exh. CTM-1T at 43-44.
[77] *See generally Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-111048/UG-111049, Order 08 (May 7, 2012).
[78] Mickelson, Exh. CTM-1T at 59:17-19.
[79] *Id.* at 59:12-19.

Q. What are PSE's proposed changes to its basic charges for its electric service?

A. PSE proposes implementing changes to its various basic charges over the course of its three-year MYRP. For each rate year, PSE's proposal includes a potential annual increase of up to 35 percent in its basic charge while not exceeding each rate schedule's COS study indicated result. For PSE's residential customers, the charge may increase by more than 35 percent since the charge has largely remained the same since Docket UE-111048.[80] In other words, PSE's 35 percent increase operates as a cap on annual movement, applied year over year, to move each of its rate schedules towards its cost-based levels. A full breakout of PSE's proposed basic charge increases is found on Table 7, below.

Table 7: PSE as-Filed Electric Service Basic Charge Incereases

Line No.	Rate Schedule [A]	Test Year [B]	Gap Year [C]	RY1 [D]	RY2 [E]	RY3 [F]
1	Schedules 7/307/327 Residential Service - Single Phase	$ 7.49	$ 7.49	$ 12.50	$ 15.00	$ 20.00
2	Schedules 7/307/327 Residential Service - Three Phase	$ 17.99	$ 17.99	$ 21.65	$ 25.98	$ 34.64
3	Schedule 08 (24) Secondary Voltage General Service - Single Phase	$ 10.21	$ 10.21	$ 13.78	$ 18.61	$ 25.12
4	Schedule 08 (24) Secondary Voltage General Service - Three Phase	$ 25.95	$ 25.95	$ 35.03	$ 47.29	$ 63.85
5	Schedule 7A (11) (25) Secondary Voltage Small Demand General Service	$ 70.14	$ 91.18	$ 123.09	$ 166.18	$ 224.34
6	Schedules 12/26/26P Secondary Voltage Large Demand General Service	$ 218.16	$436.32	$ 589.03	$ 795.19	$ 1,073.51
7	Schedule 29 Secondary Voltage Irrrigation & Pumping Service	$ 12.99	$ 16.88	$ 22.79	$ 30.76	$ 41.53
8	Schedule 10 (31) Primary Voltage General Service	$ 465.54	$605.21	$ 817.03	$ 1,103.00	$ 1,489.04
9	Schedule 43 Primary Voltage Interruptible Schools	$ 465.54	$605.21	$ 817.03	$ 1,103.00	$ 1,489.04
10	Schedule 558 (Optional Service)	$ -	$890.94	$ 1,202.77	$ 1,623.73	$ 2,192.04

Notes and Sources
[1] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "Exh CTM-Rate Design".

For example, PSE's General Service Rate Schedule (Schedule 24) would see an increase in its basic charge by up to 35 percent annually, from $10.21 (single phase)

[80] *Id.* at 57 n. 13.

and $25.95 (three phase) to $13.78 / $35.03 in RY1, to $18.61 / $47.29 in RY2, and $25.12 / $ 63.85 in RY3.

Q. Do you believe additional scrutiny is merited?

A. Yes. In an effort to assess the reasonableness of PSE's proposed basic charge increases, I compare the as-filed amounts to an independent analysis that applies the Commission's direct-customer-cost principles from *Washington Utilities and Transportation Commission v. Pacific Power & Light Company* (Pacific Power), Docket UE-140762, Order 08, and economic principles drawn from *The Economics of Public Utility Regulation.*

Q. How has the Commission previously ruled on the appropriate components and implementation of a basic charge?

A. The Commission has long maintained the principle that a utility's basic charge should be limited to a direct set of customer-related costs.[81] In the Commission's final order in Pacific Power's 2014 GRC, it stated that it was "not prepared to move away from the long-accepted principle that basic charges should reflect only 'direct customer costs' such as meter reading and billing." The Commission also rejected proposals to significantly increase the residential basic charge by 81 percent through the inclusion of broader distribution costs, explaining that such an increase would reduce customers' ability to control bills through conservation.[82]

[81] 2015 PacifiCorp Order at 91 ¶ 216.
[82] *Id.*

Q. Has the Commission's approach been adopted by other state regulatory commissions nationwide?

A. Yes. A basic charge limited to a direct set of customer-related costs has been adopted by several other state regulatory commissions. Examples of which include Texas and Connecticut, who limit the customer charge to "costs that vary by customer such as metering, billing and customer service" and "only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service," respectively.[83] Although the precise implementation differs among jurisdictions, these approaches similarly separate direct-customer-costs from a broader set of system costs that may be classified as customer related in a COS study.

Q. Does the Commission's previous ruling on basic charge increases follow broader economic theory?

A. Yes. A common understanding of the importance of limiting the recovery of a utility's fixed costs is best explained in *The Economics of Public Utility Regulation* by Michael A. Crew and Paul R. Kleindorfer. In their discussion of regulated utilities, they emphasize that utilities are natural monopolies which are characterized by substantial fixed and sunk costs due to investment in infrastructure that does not vary with customer usage. Accordingly, there is a need for a fixed level of recovery

[83] Lien, Exh. ZML-6 at 145 & 243.

of these costs, since marginal cost revenues alone cannot be sufficiently designed to meet a utility's full revenue requirement.[84]

However, a strict reliance on cost-based accounting of a utility's fixed costs can lead to economically inefficient pricing, since using a fully distributed cost formula does not account for the differences in demand elasticity.[85] For economic efficiency, a utility's fixed cost recovery should generally be assigned in a manner that facilitates a relatively small markup for customers who have more elastic demand (more price sensitive) and a larger markup for customers with less elastic demand (less price sensitive). Simply stated, broadening the number of fixed cost items eligible for recovery through the basic charge reduces the importance of volumetric pricing, thereby weakening efficient consumption incentives and increasing the potential for economically inefficient outcomes.

Q. Are there additional rate design goals that must be taken into consideration when examining PSE's proposed basic charge increase?

A. Yes. Beyond the economic efficiency principles discussed above, a higher basic charge carries two additional policy implications worth the Commission's consideration, given that a higher basic charge will reduce the utility's share of revenue recovered through its volumetric, energy-based rates: (1) increasing the basic charge reduces risk for the utility by shifting revenue recovery towards a fixed monthly charge, which is then collected regardless of consumption, and (2)

[84] Lien, Exh. ZML-7 at 3.
[85] *Id.*

increasing the basic charge may undermine Washington State's energy efficiency and clean energy policy goals by discouraging conservation and reducing incentive for customers to manage their electricity consumption through behavior-based approaches.[86]

Q. Considering the principles discussed above, what standard do you apply to determine which costs are appropriate to include in PSE's residential basic charge?

A. Consistent with the Commission's ruling in Pacific Power's 2014 GRC, I apply a direct-customer-cost standard to determine which costs are eligible for recovery through PSE's residential basic charge. Under this standard, I include only costs that are directly associated with establishing and maintaining an individual customer's connection to the utility system, metering the customer's usage, reading the meter, billing the customer, and maintaining the customer account.

Importantly, I do not include broader distribution system costs, general administrative costs, customer program costs, or other costs simply due to their classification as customer related in the COS study. As discussed above, a COS study classification identifies the driver of a cost but does not resolve the separate rate design question of which customer-related costs should be recovered through PSE's basic charge. Including a greater share of non-direct customer-related costs would risk the same economically inefficient outcomes discussed above: it would

[86] Joshua M. Pearce, Paul J. Harris, *Reducing greenhouse gas emissions by inducing energy conservation and distributed generation from elimination of electric utility customer charges*, Energy Policy Volume 35, Issue 12, 2007, at 6514-6525, *available at* https://doi.org/10.1016/j.enpol.2007.08.029.

shift a larger share of PSE's revenue recovery away from volumetric rates, thereby diminishing the price signals that encourage conservation and reducing customers' ability to manage their bills through their own usage decisions. The narrower, direct set of customer-related costs that I propose to include are incurred simply by virtue of a customer's connection to PSE's system, regardless of their usage. This approach is consistent with both the Commission's own precedent and the economic principles discussed above.

Q. What accounts do you propose to include in the basic charge?

A. I include FERC accounts that satisfy the direct customer-related cost standard discussed above. Specifically, I include accounts reasonably associated with service connections, metering, meter maintenance, billing, and maintaining customer account records – all costs that are incurred regardless of usage. A full list of the FERC accounts that I include, along with their relevant balances, is depicted in Table 8, below.

Table 8: Staff Calculated Electric Customer Costs

Line No.	FERC Account [A]	Description[1] [B]		Res Svc [C]
		Distribution Operation Expenses		
1	586	Meter Expenses	$	2,814,899
2	587	Customer Installation Expenses	$	5,248,722
		Distribution Maintenance Expenses		
3	597	Maintenance of Meters	$	388,731
		Customer Accounting Expenses		
4	901	Supervision	$	145,812
5	902	Meter Reading	$	6,921,434
6	903	Customer Records & Collections	$	20,642,309
7	905	Misc Customer Accounts Expenses	$	2,787,515
		Depreciation Expense [2]		
8	369.01	Services - Overhead	$	1,240,042
9	369.02	Services - Underground	$	4,293,260
10	370	Meters – Depreciation Expense	$	11,720,968
11	371	Installations on Cust Premises – Depreciation Expense	$	1,628,161
12		**Total [3]**	**$**	**57,831,853**

Notes and Sources

[1] Mickelson, Workpaper CTM-3, Tab "CustomerTotal".

[2] Accrual rates based on PSE witness Ned W. Allis' findings, Workpaper NWA-3-ELE, Table 1.

[3] Lien, Exh. ZML-3, Tab "Staff Customer Costs".

With respect to service connection and metering costs, I include the direct operating and maintenance expenses associated with FERC Accounts 586 – Meter Expenses, 587 – Customer Installation Expenses, and 597 – Maintenance of Meters. I also include the annual cost associated with service connection and metering plant, including FERC Accounts 369.01 – Services Overhead, 369.02 – Services Underground, 370 – Meters, and 371 – Installations on Customers' Premises.

Consistent with that same standard, I include FERC Accounts 901 – Supervision, 902 – Meter Reading, 903 – Customer Records & Collections, and

905 – Misc Customer Accounts Expenses. These accounts support the recurring administrative functions necessary to read meters, issue bills, maintain customer records, and administer customer accounts, and are thus considered relevant when calculating an appropriate basic charge for PSE's residential customers.

Q. Using the FERC Accounts mentioned above, how did you calculate an appropriate residential basic charge?

A. To begin, I total the appropriate customer-related costs from PSE's filed cost-of-service data. These costs amount to roughly $57.83 million.[87] I then add the associated income taxes, return on rate base, and revenue-related expenses to determine an annual basic charge-related net cost of approximately $85.04 million, as shown in Table 9, below.

[87] Lien, Exh. ZML-3, Tab "Staff Customer Costs."

Table 9: Staff Calculated Residential Electric Basic Charge			
Line No.	Description [A]		Res Svc [B]
1	Non-Revenue Costs	$	57,831,853
2	Income Tax	$	516,149
3	Return on Rate Base	$	26,600,847
4	Rev. Related Items	$	89,127
5	**Net Cost [1]**	**$**	**85,037,976**
6	Bill Determinants [2]		
	Single-Phase		13063955
	Three-Phase		4524
	Total		13068479
7	Indicated Basic Charge [3]		
	Single-Phase	**$**	**6.50**
	Three-Phase	**$**	**15.62**
	General		**N/A**

Notes and Sources

[1] Mickelson, Workpaper CTM-3-E-COS-Model, Tab "GrandTotal."

[2] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "CTM-6 (Tariff)."

[3] Exh. ZML-3, Tab "Staff COS Basic Charge".

Q. Before applying Staff's net cost, please explain the difference between single-phase and three-phase service.

A. Single-phase and three-phase service differ in regard to how alternating current electricity is delivered to a customer.[88] Single-phase service delivers power over a single, alternating current wave form and is the standard for the majority of residential customers, since it is sufficient to serve typical household needs, such as

[88] Dustin Stelzer, *Single Phase vs. Three Phase Power*, Electrician U (July 8, 2024), *available at* https://electricianu.com/single-phase-vs-three-phase-power/

lighting, small appliances, and standard heating and cooling equipment. Three-phase service, in comparison, delivers power across three separate waveforms and is generally reserved for premises with larger and/or more specialized electrical loads.

Because three-phase service requires additional costs to install and maintain service, the direct customer related cost of connecting these customers is higher than that of a single-phase customer. This cost difference is the basis for PSE's tariff phase weighting, which assigns a proportionally higher basic charge to three-phase customers.

Q. How do you incorporate this phase-based cost difference into your calculation of PSE's residential basic charge?

Lastly, I divide the annual residential net cost by PSE's number of Test Year customer bills, as contained in PSE's rate model.[89] I retain PSE's effective tariff phase weight for residential single-phase and three-phase customers, and apply PSE's residential Test Year bill determinants of 13,063,955 for annual single-phase customer bills and for 4,524 annual three-phase customer bills. As a result, I calculate a monthly customer charge of $6.50 for single-phase residential service customers and $15.62 for three-phase residential service customers.

Q. Please state your position as it relates to PSE's proposed residential electric basic charge increase.

[89] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "CTM-6 (Tariff)."

A. Applying the direct set of customer-related costs described above, my analysis demonstrates a basic charge far lower than the amounts PSE has proposed. Because my analysis limits the included accounts to those directly attributable to the costs of service connections, metering, meter reading, billing, and maintaining customer accounts, it is consistent with the Commission's ruling in Pacific Power's 2014 GRC, which held that residential basic charges should recover only direct customer-related costs. My recommendation also preserves meaningful volumetric price signals and customers' ability to manage their bills through changes in usage.

Although the calculated residential basic charge is below PSE's existing level, I do not recommend reducing the charges in this proceeding. Maintaining the existing charges avoids unnecessary rate-design disruption and maintains bill simplicity. At the same time, rejecting PSE's proposed increases prevents the residential basic charge from moving even farther above the cost-supported level established by my direct-cost analysis. Accordingly, I recommend that the Commission reject PSE's proposed residential basic charge increases and maintain the current residential basic charge throughout the MYRP.

Q. Do you recommend any other changes to PSE's proposed electric basic charges?

A. Yes, I recommend that the Commission apply the same direct-customer-cost standard used in my residential analysis to PSE's general service customers served under rate schedules 8/24 and 7A/11/25/29. In Order 08 of Pacific Power's 2014 GRC, the Commission stated that it was "not prepared to move away from the long-accepted principle that basic charges should reflect only 'direct customer costs' such

as meter reading and billing."[90] Although that discussion addressed residential service, the principle addresses the nature of the cost rather than the type of customer. As such, the same rate design concept applies here: Metering, meter reading, billing, and account administration remain direct customer-related costs when provided to a general service customer, while broader distribution facilities do not become direct customer costs merely because they are used to serve that customer.

Accordingly, I apply the same account-selection standard that was included in my residential analysis due to their representation of functions most closely tied to establishing service, measuring usage, issuing bills, and maintaining the customer's account. This approach also recognizes that three-phase and higher-demand general service customers require more costly service and metering configurations than single-phase lower-demand customers; those costs differences are already present through PSE's class allocations and applicable phase weighting, and they provide no basis for expanding the basic charge to recover broader distribution costs that have not been properly attributed to serving an individual customer.

[90] 2015 PacifiCorp Order at 91 ¶ 216.

Table 10: Staff Calculated Electric Basic Charge					
Line No.	Description [A]	Res Svc [B]	General Service, <51 kW [C]	General Service, 51-350 kW [D]	
1	Non-Revenue Costs	$ 57,831,853	$ 13,006,956	$ 3,358,761	
2	Income Tax	$ 516,149	$ 99,227	$ 18,832	
3	Return on Rate Base	$ 26,600,847	$ 5,113,901	$ 970,552	
4	Rev. Related Items	$ 89,127	$ 19,116	$ 4,562	
5	**Net Cost [1]**	**$ 85,037,976**	**$ 18,239,201**	**$ 4,352,707**	
6	Bill Determinants [2]				
	Single-Phase	13063955	1134095	N/A	
	Three-Phase	4524	482155	N/A	
	Total	13068479	1616250	100522	
7	Indicated Basic Charge [3]				
	Single-Phase	**$ 6.50**	**$ 7.73**	**N/A**	
	Three-Phase	**$ 15.62**	**$ 19.65**	**N/A**	
	General	**N/A**	**N/A**	**$ 43.30**	

Notes and Sources

[1] Mickelson, Workpaper CTM-3-E-COS-Model, Tab "GrandTotal."

[2] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "CTM-6 (Tariff)."

[3] Exh. ZML-3, Tab "Staff COS Basic Charge".

As shown in Table 10, expanding the application of the direct-customer cost methodology results in indicated monthly basic charges of $7.73 for single-phase and $19.65 for three-phase general service customers below 51 kW, and $43.30 for customers between 51 and 350 kW. Even after recognizing the greater average cost associated with three-phase and higher-demand general service customers, these indicated charges remain materially below PSE's proposed existing charges and increases. PSE has therefore not demonstrated how its proposed charges to general service rate schedules, which extend beyond the charges calculated above, align with the Commission's long-accepted standard of direct-customer costs. Accordingly, I

recommend that the Commission reject PSE's proposed increases to general service customers served under rate schedules 8/24 and 7A/11/25/29.

B. TOU Schedules

Q. Is Staff proposing any adjustments to PSE's proposed TOU rate structure?

A. Yes. Staff generally supports PSE's proposal to transition Schedules 307 and 327 from that of limited pilot participation to full-scale, voluntary residential TOU schedules and to remove the existing participation caps. However, as described by Staff Witness Dr. Halliday, Staff does not fully support PSE's proposed redesign of the applicable time periods.

Staff's ratemaking model incorporates Dr. Halliday's recommended adjustments to PSE's proposed TOU rates.[91] Such changes are designed to establish a closer link to the schedules actually tested during the pilot, recognize seasonal system conditions, retain morning peak pricing where appropriate, and shorten PSE's proposed five-hour evening peak period.[92] Dr. Halliday's adjustments are intended to preserve PSE's price signals during both morning and evening periods of heightened system demand while avoiding an evening peak window that may be too long for residential customers to respond to effectively.

[91] Lien, Exh. ZML-4, Tab "Exh ZML-TVR Bill Impacts."
[92] Halliday, Exh. HSH-1T at 3:5-13.

C. Residential Rate Tiers

Q. Please explain the role of an energy tier, and how it applies to PSE's residential electric rates.

A. An energy tier is a billing structure that is designed to change the volumetric energy charge (the rate per kWh), based on how much electricity a customer uses within a billing period. Specifically, rather than applying a flat rate to all usage, PSE's residential rate schedule (Schedule 7) uses a two-tier structure: the first 600 kWh of a customer's monthly usage are billed at the lower "Tier 1" rate, while the remaining usage that exceeds 600 kWh in that month is billed at the "Tier 2" rate.[93] This inclining block structure is commonly used as a means of promoting conservation by applying higher rates to higher levels of consumption while maintaining a comparatively lower rate for basic household usage.

Q. Is PSE proposing any modification of its residential energy tiers in this proceeding?

A. Yes. PSE proposes to retain its existing two-tier residential rate structure and tier breakpoint (600 kWh) while introducing an explicit "Tier 2 multiplier" that formally ties the percentage rate increase to Tier 2 to a multiple of the percentage rate applied to Tier 1.[94] PSE states that the purpose of this approach is "to maintain revenue

[93] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "Exh CTM-Tariff."
[94] Mickelson, Exh. CTM-1T at 69:7-12.

sufficiency and support gradualism, while directing a proportionate share of the overall class-level increase to usage above the Tier 1 threshold."[95]

Q. Please describe how PSE's proposed Tier 2 multiplier changes over the course of the MYRP.

A. As reflected in PSE's ratemaking workpaper, the Company's proposed multiplier is not constant across the MYRP, but instead varies across the rate year.[96] Applying these multipliers to the company's filed class-average increases for Schedule 7 produces the following Tier 1 and Tier 2 percentage increases:

Table 11: PSE's Proposed Residential Pricing Structure

Line. No	Description [A]	RY1 [B]	RY2 [C]	RY3 [D]
1	Tier 2 Multiplier [1]	0.8	1.3	1.8
2	Tier 1 Energy Rate Increase [2]	46.96%	1.69%	5.11%
3	Tier 2 Energy Rate Increase	37.57%	2.19%	9.21%

Notes and Sources:
[1] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "Exh CTM-Rate Design", Columns T-V, Line 7.
[2] *Id.,* Tab "Exh CTM-Rate Design", Columns I-K, Lines 8-9.

In RY1, Tier 2's percentage increase (37.57 percent) is smaller than Tier 1's (46.96 percent), indicating that usage above PSE's existing 600 kWh threshold receives a comparatively smaller rate increase than the Company baseline usage. In RY2 and RY3, PSE's multiplier exceeds 1.0, and rather than continuing to close the pricing

[95] *Id.* at 68:14-17
[96] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "Exh CTM-Rate Design," Columns T-V, Line 7.

gap between Tier 1 and Tier 2, PSE's proposed residential pricing structure reverses course: the absolute price differential between Tier 1 and Tier 2 widens in both years, resulting in RY3 rates that more closely mirror the gap under present rates.

Table 12: PSE's Proposed Residential Pricing Structure Rate Differential

Line No.	Description [A]	Tier 1 Rate ($/kWh)[1] [B]	Tier 2 Rate ($/kWh) [C]	Absolute Differential [D]	% Differential [E]	Result [F]
1	Test Year	0.133017	0.152434	0.019417	14.60%	-
2	Gap Year	0.141598	0.161015	0.019417	13.71%	Gap Narrows
3	RY1	0.208096	0.221509	0.013413	6.45%	Gap Narrows
4	RY2	0.211606	0.226365	0.014759	6.97%	Gap Begins to Restore
5	RY3	0.222429	0.247206	0.024777	11.14%	Gap Close to Present Rates

Notes and Sources

[1] Mickelson, Workpaper CTM-4-E-Ratemaking-Portfolio, Tab "Exh CTM-Rate Design", Columns G-K, Lines 8-9.

Q. How does PSE's MYRP interact with its proposed Tier 2 multiplier?

A. PSE's own tiered impact analysis demonstrates that residential usage is highly seasonal, with average monthly usage peaking during the winter months. As an example, the average residential usage is approximately 1,158 kWh in December and 1,144 kWh in January, while being 750 kWh and 654 in August and September, respectively.[97] Because PSE's existing residential pricing structure caps Tier 1 usage at 600 kWh per month, nearly half of a residential consumer's winter-month usage falls into the higher priced Tier 2 block.

[97] *Id.,* Tab "Exh. CTM-Res Bill Impacts."

This seasonal concentration of Tier 2 usage means that the Tier 2 multiplier has an outsized effect on winter bills specifically, relative to its effect on more moderate summer bills. In RY1, PSE's multiplier of 0.8 works to reduce the risk of winter rate shock by having Tier 2 receive a smaller percent increase (37.57 percent) than Tier 1 (46.96 percent). In other words, the rate component that is more present in high-usage winter bills is increasing at a slower rate than the component that is present during the comparatively lower usage summer bills, which tempers the bill impact in the months where residential customers are using and paying for the most energy.

PSE's Tier 2 multiplier shifts in RY2 and RY3, rising above 1.0. As shown in Tables 11 and 12, this results in Tier 2 rising faster in terms of percentage terms than Tier 1, which works to gradually restore the rate differential between Tier 1 and Tier 2 so that it approaches that which exists under present rates. Under PSE's proposed approach, the impact of increasing Tier 2 rates is not absorbed all at once but is instead moved incrementally across RY2 and RY3.

Q. Do you support PSE's proposed Tier 2 multiplier when adopting Staff's MYRP revenue requirements?

A. Yes. As discussed above, PSE designed its Tier 2 multiplier to compress the proposed rate increase in RY1, where the rise in the incremental revenue requirement carries the greatest risk of rate shock. My analysis of the incremental revenue requirement under Staff's adjusted revenue requirement confirms that this design remains appropriate. Specifically, Staff's revenue requirement produces an

incremental revenue requirement increase of $683.86 million in RY1, $208.91 million in RY2, and $415.60 million in RY3.[98] As such, RY1 continues to carry the largest rate impact through the course of PSE's MYRP, with RY3 rising again after a comparatively modest RY2.

Table 13 demonstrates the effect of retaining PSE's Tier 2 multiplier against removing it entirely under Staff's revenue requirements. When PSE's proposed multiplier is retained, Tier 2 rates rise by 16.63 percent in RY1, compared to 18.88 percent if the multiplier were removed. Because RY1 is the year in which the incremental revenue requirement, and therefore the risk of rate shock, is greatest, removing PSE's multiplier would impose the largest Tier 2 increase in precisely the year that increase is least appropriate. Accordingly, PSE's multiplier continues to serve its intended function under Staff's rates: tempering the Tier 2 rate impact in the year it would otherwise be most prevalent, while allowing the Tier 1 and Tier 2 rate differential to be gradually restored in RY2 and RY3.

[98] Lien, Exh. ZML-4, Tab "Exh. ZML-Rate Spread", Columns M-O, Line 35.

Table 13: Assessing PSE's Tier 2 Multiplier Under Staff's Rates

		Rates Under PSE's Tier 2 Multiplier			Rates Under a Removed Multiplier		
Line No.	Description [A]	Tier 1 Rate ($/kWh)[1] [B]	Tier 2 Rate ($/kWh)[2] [C]	% Change to Tier 2 Rates[3] [D]	Tier 1 Rate ($/kWh) [E]	Tier 2 Rate ($/kWh) [F]	% Change to Tier 2 Rates [G]
1	Test Year	0.133017	0.152434	-	0.133017	0.152434	-
2	Gap Year	0.141598	0.161015	5.63%	0.141598	0.161015	5.63%
3	RY1	0.171027	0.187787	16.63%	0.168327	0.191410	18.88%
4	RY2	0.177060	0.196398	4.59%	0.175065	0.199071	4.00%
5	RY3	0.187179	0.216601	10.29%	0.188692	0.214567	7.78%

Notes and Sources

[1] Lien, Exh. ZML-4, Tab "Exh ZML-Res Bill Impacts". Columns C-F, Lines 4 and 5.

[2] Rates are calculated using PSE's proposed basic charge rate for ease of reference.

[3] Lines 1 and 2 reflect previous and existing rates and are not impacted by the proposed multiplier.

Q. Did PSE consider any other changes to its residential rate design structure?

A. Yes. PSE also evaluated two structural alternatives to its present residential rates: (1) expanding the Tier 1 breakpoint from 600 kWh to 800 kWh to better match the lower tier with typical household usage, and (2) moving to an illustrative three-tier structure which would include "essential" (0 – 300 kWh), "whole-house" (300 – 1200 kWh), and "discretionary" (greater than 1200 kWh) use tiers.[99] However, PSE described such changes as "premature", citing the complexity of assessing bill impacts, distributional effects on different customer segments, interactions with low income programs that would be better addressed in a non-rate case setting to promote collaborative refinement.[100]

[99] *Id.* at 70:9-18.
[100] *Id.* at 71:19-27.

Q. Do you support PSE's proposal to workshop structural changes to its residential tier design outside of this proceeding?

A. Yes. As discussed above, PSE evaluated but declined to propose structural alternatives to its existing tier design. These alternatives comprised of (1) expanding the Tier 1 breakpoint from 600 kWh to 800 kWh, and (2) adopting a three-tier structure that established tiers based on various household usage assumptions.[101] PSE characterized both alternatives as premature for adoption in this proceeding, citing to the complexity of assessing bill impacts, distributional effects across customer segments, and interactions with low-income assistance programs: all of which will be conditional on outcome of this proceeding.[102]

I agree that a GRC, with its compressed procedural schedule, is not well suited to fully vetting structural changes to the extent PSE proposes to further examine, which can have significant and uneven effects across different usage levels. I therefore support PSE's recommendation that any reconsideration of its existing residential Tier 1 breakpoint be taken up in a workshop setting outside of this proceeding, where PSE, Staff, and other interested parties can collaboratively refine bill impact modeling, distribution effects, and how these changes interact with low-income programs.

Q. Do you have any additional recommendations with regard to future changes to PSE's residential energy rate?

[101] Mickelson, Exh. CTM-1T at 70:9-18.
[102] *Id.* 71:19-27.

A. Yes. Consistent with my support of PSE's proposed workshop to investigate structural tier alternatives, I recommend that any further refinement of PSE's pricing differential between its Tier 1 and Tier 2 residential rates be addressed in a similarly collaborative workshop setting. As PSE recognizes, any changes to residential tier pricing raise distributional concerns and, as a result, benefit from deliberate, collaborative processes outside of a rate case proceeding. Specifically, I recommend that the workshop consider whether PSE's residential pricing differential should ultimately be narrower, wider, or held at its projected level by the end of the MYRP. Such question should be addressed in coordination with PSE's number of residential tiers and the affiliated kWh breakpoint as a single body of work.

VII. RESULTS AND BILL IMPACTS

A. Overview

Q. Please summarize Section VII of your testimony.

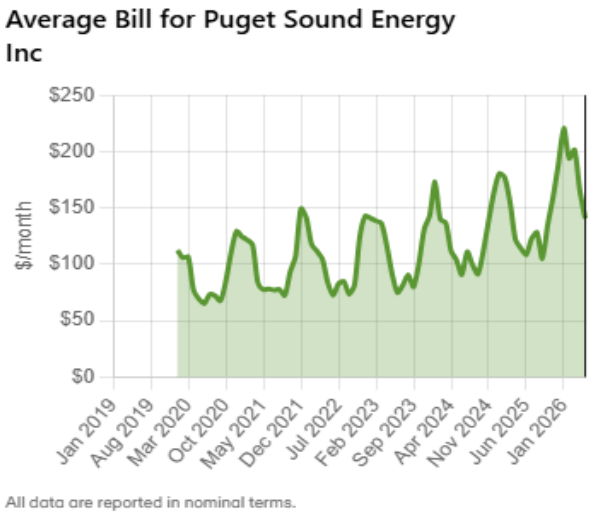
A. Section VII presents my calculated average bill and average rate impacts for residential customers served by PSE, for each rate year of the company's proposed MYRP, after applying Staff's adjustments. These impacts are designed to reflect Staff's recommended revenue requirement, together with my recommended rate spread and rate design.

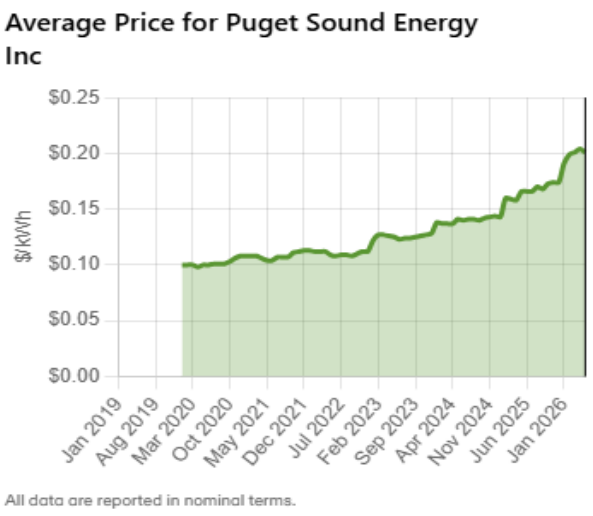
Section VII compares the average bill and average rate impacts resulting from these recommendations against those resulting from PSE's as-filed proposal, for a residential customer at PSE's average usage level in each rate year. This comparison is intended to illustrate, in residential customer-facing terms, the practical effect of the adjustments discussed in my testimony, and to provide the Commission with a basis for evaluating the reasonableness of the resulting customer impacts relative to PSE's proposal.

Q. Please discuss the benefit of discussing both average bill and average rate.

A. Discussing both average bill and average rate avoids understating or otherwise misconstruing the residential customer impacts of Staff's recommendations. While an average bill represents the average total monthly amount paid by the customer to the utility, the average rate (price) reflects the volumetric cost of energy consumed per kWh. Because a residential average bill is a function of both price and usage, it is subject to considerable variation month-to-month due to seasonal weather patterns and other usage-related factors, independent of any underlying changes in rates. The average rate, in contrast, isolates the price component by dividing total charges by total usage. This approach effectively smooths out variation in seasonal usage consumption and provides a clearer measure of the rate per unit of energy. However, it can also be less intuitive when evaluating total impacts, as customers ultimately experience changes through their monthly bills, not an average per-unit rate. The differences between both the average residential bill and average residential rate are shown in Figure 2, below:

Figure 2: Average Bill vs. Average Rate for Residential Customers Served by PSE





Notes and Sources:

[1] Results extracted from the "Electricity Price Hub" from the Heatmap News Website, https://electricity.heatmap.news/.

[2] Data selected to reflect PSE's entire Washington service area.

By presenting both the average bill and the average rate impacts of Staff's recommendations, the Commission and other parties can evaluate the customer-facing effect of Staff's proposal from two complementary perspectives: the average rate isolates the price effect directly attributable to this rate case, while the average bill reflects what a typical residential customer served by PSE can expect to pay.

B. Electric Service

Q. What is Staff's proposed electric bill impacts for PSE's residential service customers?

A. For purposes of comparing bill impacts, Staff uses an average monthly usage level of approximately 865 kWh, based on Staff's recommended weather-normalization

adjustments. This usage level is held constant when calculating bills under present rates and Staff versus PSE's residential bill impacts.

At 865 kWh per month, a residential customer's average monthly bill under present rates is approximately $172.74, holding seasonality constant. Applying Staff's adjustments to RY1, this average monthly bill increases to $181.01, which represents an approximate 10.68 percent reduction from PSE's requested average monthly bill of $202.66.[103] Throughout the course of PSE's MYRP, Staff's adjustments result in a cumulative 18.88 percent increase in the average monthly bill, from PSE's present average bill to RY3, as compared to the Company's cumulative proposed increase of 31.22 percent over the same period.[104] Staff's proposed bill impact therefore represents an approximate 39.53 percent reduction from PSE's proposed total percentage increase to the average residential bill. For a complete reference of Staff's proposed bills under various rate years and usage assumptions, please see Table 14, below.

[103] Mickelson, Workpaper CTM-4-Ratemaking-Porfolio, Tab "Exh CTM-Res Bill Impacts," Column E, Line 52.
[104] Lien, Exh. ZML-4, Tab "Exh ZML-Res Bill Impacts."

Table 14: Staff Proposed Bill Impacts for Residential Service Customers

Line No.	Usage (in Monthly kWh) [A]	Present Bill [B]	Proposed RY1[1] [C]	Proposed RY2 [D]	Proposed RY3 [E]	Total % Change [F]
1	0	$ 7.49	$ 7.49	$ 7.49	$ 7.49	0.00%
2	50	$ 16.75	$ 17.27	$ 17.70	$ 18.41	9.91%
3	100	$ 26.00	$ 27.05	$ 27.90	$ 29.33	12.81%
5	200	$ 44.51	$ 46.62	$ 48.32	$ 51.16	14.94%
6	300	$ 63.02	$ 66.18	$ 68.73	$ 73.00	15.84%
7	400	$ 81.53	$ 85.75	$ 89.15	$ 94.84	16.33%
8	500	$ 100.04	$ 105.31	$ 109.56	$ 116.68	16.63%
9	600	$ 118.55	$ 124.88	$ 129.98	$ 138.51	16.84%
10	700	$ 139.00	$ 146.06	$ 152.37	$ 163.74	17.80%
11	800	$ 159.46	$ 167.25	$ 174.76	$ 188.97	18.51%
12	**865**	**$ 172.74**	**$ 181.01**	**$ 189.30**	**$ 205.35**	**18.88%**
13	900	$ 179.91	$ 188.43	$ 197.15	$ 214.19	19.05%
14	1000	$ 200.36	$ 209.62	$ 219.54	$ 239.42	19.49%
19	1500	$ 302.62	$ 315.55	$ 331.50	$ 365.55	20.80%
20	2000	$ 404.88	$ 421.48	$ 443.47	$ 491.68	21.44%
22	3000	$ 609.40	$ 633.34	$ 667.39	$ 743.95	22.08%
23	4000	$ 813.92	$ 845.20	$ 891.31	$ 996.21	22.40%
24	5000	$ 1,018.44	$ 1,057.06	$ 1,115.23	$ 1,248.48	22.59%

Notes and Sources
[1] Lien, Exh. ZML-4, Tab "Exh ZML-Res Bill Impacts".

Q. Please summarize Staff's proposed electric rate impacts for PSE's residential service customers.

A. Currently, the average ratepayer who uses 865 kWh a month pays an average rate of $0.19105 per kWh, including PSE's relevant tiered energy rates and its pass-through charges. When applying Staff's adjustments to PSE's RY1 revenue requirement, this rate increases to approximately $0.20061 per kWh, which equates to a reduction of 8.76 percent from PSE's requested average rate of $0.21984 per kWh for RY1. Throughout the course of PSE's MYRP, Staff's adjustments result in a cumulative 19.73 percent increase in the average monthly rate, from PSE's present average bill

to RY3, as compared to the Company's cumulative proposed increase of 25.07 percent over the same period.[105] Staff's proposed relevant rate impact therefore represents an approximate 21.28 percent reduction from PSE's proposed total percentage increase to the average residential rate. A breakout of Staff's proposal under various rate years and usage assumptions is found on Table 15, below.

Table 15: Staff Proposed Rate Impacts for Residential Service Customers

Line No.	Usage (in Monthly kWh) [A]	Present Bill [B]	Proposed RY1 [C]	Proposed RY2 [D]	Proposed RY3 [E]	Total % Change [F]
1	0	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
2	50	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
3	100	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
5	200	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
6	300	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
7	400	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
8	500	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
9	600	$0.18510	$0.19564	$0.20414	$0.21837	17.97%
10	700	$0.18788	$0.19796	$0.20697	$0.22321	18.81%
11	800	$0.18996	$0.19970	$0.20909	$0.22685	19.42%
12	**865**	**$0.19105**	**$0.20061**	**$0.21020**	**$0.22876**	**19.73%**
13	900	$0.19158	$0.20105	$0.21074	$0.22967	19.88%
14	1000	$0.19287	$0.20213	$0.21205	$0.23193	20.25%
19	1500	$0.19675	$0.20537	$0.21601	$0.23871	21.32%
20	2000	$0.19870	$0.20700	$0.21799	$0.24210	21.84%
22	3000	$0.20064	$0.20862	$0.21997	$0.24549	22.35%
23	4000	$0.20161	$0.20943	$0.22095	$0.24718	22.60%
24	5000	$0.20219	$0.20991	$0.22155	$0.24820	22.75%

Notes and Sources
[1] Lien, Exh. ZML-4, Tab "Exh ZML-Res Bill Impacts".

VIII. CONCLUSION

Q. Please summarize Staff's recommendations.

[105] Lien, Exh. ZML-4, Tab "Exh ZML-Res Bill Impacts."

A. Applying the analysis discussed throughout my testimony, I conclude that PSE's as-filed electric COS study requires several adjustments to appropriately reflect the Company's expected COS. Accordingly, I recommend that the Commission adopt Staff's adjusted COS study, which incorporates Staff's adjustments to PSE's present revenue from rates and revenue requirement at unity, RFPC calculation, and weather normalization methodology. While these adjustments meaningfully reduce PSE's total revenue requirement at unity, they do not substantially alter PSE's COS indicated parity findings. As such, I recommend that the Commission apply PSE's own parity-band rate spread methodology, which I find reasonable, to Staff's recommended revenue requirements rather than PSE's as-filed proposal.

Additionally, I recommend that the Commission direct PSE to file an updated, recalculated COS study no later than six months before RY3 begins. The study should use the most recent consecutive 12 months of actual data available at the time of filing, consisting of the latter portion of RY1 and the available portion of RY2. PSE should present the results to parties through a workshop process so that the Commission and parties can determine whether the rate-spread structure approved in this proceeding continues to reflect cost-causation principles and remains appropriate for RY3. Should the Commission reject my primary recommendation to recalculate the full COS study, I recommend, at a minimum, that PSE refresh the demand study component of its COS study using the same defined 12-month period and present the resulting demand allocators to parties through a similar workshop process.

With respect to rate design, I recommend that the Commission limit PSE's residential and applicable general service basic charges to direct, customer-related costs that are consistent with prior Commission precedent and broader policy objectives. Applying such standard results in no increase to the residential basic charge throughout the Company's proposed MYRP and supports rejecting PSE's proposed basic charge increases for the affected general service rate schedules. I further recommend that the Commission adopt PSE's proposed residential Tier 2 multipliers through the course of the MYRP. Additionally, I adopt Dr. Halliday's recommended adjustments to PSE's proposed TOU rate design. Collectively, these recommendations are intended to ensure that PSE's COS study, rate spread, and rate design each reflect accurate cost causation, while supporting rates that are fair, just, reasonable, and sufficient.

Q. Does this conclude your testimony?

A. Yes.