BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

DOCKETS UE-240004 and UG-240005 (*Consolidated*)

RESPONSE TESTIMONY OF DAVID E. DISMUKES, PH.D.
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT DED-1T

August 6, 2024

RESPONSE TESTIMONY OF DAVID E. DISMUKES, PH.D.

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. Please State your occupation and place of employment.

A. I am a Consulting Economist with the Acadian Consulting Group (ACG).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel).

Q. Please describe ACG and its areas of expertise.

A. ACG is a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and located in Baton Rouge, Louisiana.

Q. Do you hold any academic positions?

A. Yes. I am a professor emeritus at Louisiana State University (LSU). Prior to my retirement in January 2023, I served as a full professor, executive director, and director of policy analysis at the LSU Center for Energy Studies and as a full tenured professor in the Department of Environmental Sciences and the director of the Coastal Marine Institute in the LSU College of the Coast and Environment. I also served as a senior fellow at the Institute of Public Utilities at Michigan State University, where I taught energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries.

Exhibit DED-2 provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. Have you previously testified before the Washington Utilities and Transportation Commission?

A. Yes. Exhibit DED-2 includes a list of the Washington Utilities and Transportation Commission (Commission) proceedings in which I have testified, a list of all my publications, presentations, pre-filed expert witness testimony in other jurisdictions, expert reports, expert legislative testimony, and affidavits.

Q. Was this testimony prepared by you or under your supervision?

A. Yes. Although my colleagues at ACG assisted me with the research related to the formulation of my opinions, as well as the preparation of my testimony, the opinions are mine alone.

Q. What is the purpose of your testimony?

A. I have been retained by the Public Counsel Unit of the Washington State Attorney General's Office (Public Counsel) to provide expert testimony and opinions to the Commission on a number of regulatory issues implicated by the application of Puget Sound Energy (Company or PSE), including class cost of service and rate design.

Q. How is the remainder of your testimony organized?

A. The balance of my testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Class Cost of Service Study

- Section IV: Revenue Distribution
- Section V: Rate Design
- Section VI: Conclusions and Recommendations

Q. Please identify the exhibits supporting your response testimony.

A. The following Response Exhibits accompany my response testimony:

- Exhibit DED-2 Curriculum Vitae of David E. Dismukes
- Exhibit DED-3 Summary of Results of Company's Electric CCOSS
- Exhibit DED-4 Summary of Results of Alternative Electric CCOSS
- Exhibit DED-5 Company's Proposed Electric Revenue Distribution
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II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your electric Class Cost of Service Study (CCOSS) findings recommendation.

A. I recommend the Washington Utilities and Transportation Commission (Commission) adopt an alternative generation plant classification methodology that corrects the Company's faulty calculation of the Renewable Future Peak Credit (RFPC) calculation. My recommendations are consistent with the Commission's approved cost of service guidelines and simply corrects the Company's demand and energy allocators, while also providing for a more accurate representation of Puget Sound Energy's (PSE or the Company) generation costs.

Q. What is your recommendation regarding the Company's proposed electric revenue distribution?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative electric CCOSS results that also limits the first-year rate increase to any single customer class to 1.15 times the overall electric system average increase. Using the Company's proposed first-year electric system average increase of 27.6 percent, my recommendation would reduce the maximum total base revenue increase of any single rate class to 31.7 percent, compared to the Company's proposed maximum rate increase of 48.8 percent. Exceptions to this rule are made for customer classes with unique considerations such as special contract, retail wheeling, lighting service, and firm resale.

Q. What is your recommendation regarding the Company's proposed natural gas revenue distribution?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method that limits the rate increase to any single customer class to 1.25 times the overall electric system average increase. Using the Company's proposed natural gas system average increase of 51.5 percent over two years, my recommendation would reduce the maximum total base revenue increase of any single rate class to 64.3 percent, compared to the Company's proposed maximum rate increase of 77.2 percent. I also recommend the Commission hold exclusive interruptible rates constant, rather than decreasing rates as proposed by the Company.

Q. What is your recommendation regarding the Company's residential electric basic service charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in residential customer charges for a number of reasons. First, the Company's customer charge proposal is based upon an inaccurate accounting of customer-related costs, and a correct accounting shows that the current customer charge recovers all customer-related costs. Second, the Company's proposed $12.66 per month residential electric customer charge will be 14.5 percent higher than the regional average. Third, the Company's proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. Finally, the Company's proposed increase in customer charges is unnecessary to provide revenue certainty since PSE has an electric decoupling mechanism in place with allows it to reconcile differences between test year revenue per customer (RPC) and those RPCs realized between rate cases.

Q. What is your recommendation regarding the Company's general service natural gas basic service charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in general service customer charges, which includes residential customers, for several reasons. First, the Company's proposed $17.67 per month residential natural gas customer charge will be 74.2 percent higher than the regional average, and the highest residential customer charge in the region. Second, the Company's proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. Finally, the Company's proposed increase in customer charges is unnecessary to provide revenue certainty since PSE also has a revenue decoupling mechanism in place for its gas operations.

III. CLASS COST OF SERVICE STUDY

A. Introduction

Q. What is the purpose of a class cost of service study or CCOSS?

A. A "CCOSS" reconciles utility costs and revenues across different customer classes. The goal of a CCOSS is to determine the cost of providing service and revenue responsibility for each individual customer class. CCOSS results are used to estimate class specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. How is a CCOSS prepared?

A. A CCOSS utilizes a set of historic or projected cost information which is (1) "functionalized," (2) "classified," and (3) "allocated." The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by "type" including those that are (1) demand-related, (2) energy-related, or (3) customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. Can you explain what you mean by demand-related costs?

A. Yes. Demand-related costs are associated with meeting maximum electricity demands. At the electric distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. Likewise, transmission and distribution mains are designed, in part, to meet peak demand day requirements such that natural gas can be delivered to households, businesses, and industries under peak load conditions. At the electric production level, most power plants or electric generation units (EGUs) are typically viewed as being designed to serve both energy and demand/capacity needs of the utility. The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in a utility's dispatch curve, with more baseload units serving more of the utility's energy needs and more peak units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant in service costs associated with a utility's generation fleet.

Q. How are energy-related costs defined?

A. Energy or commodity-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kWh) or natural gas throughput (i.e. therms or thousand cubic feet (Mcf)) sold or transported. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales. Likewise, the investment cost of natural gas mains can be allocated, in part, on some measure of throughput.

Q. What about customer-related costs?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. Please explain the cost classification process.

A. After all costs have been identified by functional type (functionalization), a CCOSS then classifies costs based on the appropriate measure associated with each particular cost type. For example, most electric costs are classified based on their relationship to system demand, measured as either coincident peaks (CP) or non-coincident peaks (NCP). CP demand measures evaluate each class's contribution to overall system peak demand, while NCP demand measures evaluate each class's peak demand irrespective of the wider system requirements. CP demand measures are typically used in the allocation of costs associated with transmission and distribution facilities with significant diversity of loads present, while NCP measures of demand are used in the allocation of costs associated with transmission and distribution facilities that serve less diversified loads. Likewise, customer related costs may be allocated based on the number of customer accounts, or weighted customer metrics such as weighted cost of installed meters to allocate costs associated with meter reading.

Q. Please explain the allocation process.

A. A CCOSS then uses the information from the prior two steps (functionalization, classification) to allocate costs to customer classes or, in some cases, operating jurisdictions.

Q. Is the allocation process relatively straightforward?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations. For example, investments to improve both electric and natural gas distribution system reliability often provide the most benefit to manufacturing and commercial customers whose economic output and profitability is negatively impacted by service interruptions. However, distribution systems themselves are typically viewed as being designed to meet peak system demand requirements that are often driven by residential and small commercial loads. Likewise, growth caused by new or expanded industrial needs may require investment in utility systems to serve systems that again are typically themselves viewed as being designed to meet peak system demand requirements that are often driven by residential and small commercial loads.

Q. How does a CCOSS relate to commonly quoted economic principles?

A. A CCOSS is also referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. A CCOSS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with the presence of joint and common costs, difficult.

Q. Are there any other confounding problems that can arise with a CCOSS?

A Yes. There is also an issue with the fact that the cost information utilized in a CCOSS is usually historic and static, not dynamic, and forward-looking. These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in a CCOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the CCOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use CCOSS results as a "guide" in setting rates and are not bound by their results.

Q. What controversies arise in the analysis and comparison of various CCOSS methodologies?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining the amount of revenue that will be recovered through rates, the CCOSS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class; the peak load contributions of each customer class; or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can tend to shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers. These approaches can also fail to capture the service being provided by the utility and how the value of that service varies by the amount purchased by different customer classes.

Q. Please explain why methodologies that are skewed toward peak considerations shift costs towards lower load-factor customers such as residential and small commercial customers.

A. A large portion of U.S. residential and small commercial customer electricity loads are associated with weather sensitive air conditioning load. Larger industrial customers, on the other hand, use electricity within industrial processes that are typically not weather sensitive. Similarly, a large portion of U.S. residential and small commercial customer natural gas use is driven by winter heating requirements while larger industrial customers use natural gas within industrial processes that are typically not weather sensitive. Because of this, daily and annual usage patterns for residential and small commercial customer classes are significantly different from industrial customers. The peak loads for residential and small commercial customers tend to be more peaked than those for industrial customers, which are steadier and more evenly distributed across peak and non-peak periods. For example, an average residential customer has relatively little electricity use during overnight hours and during weekday daytime working hours. Residential customers do exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating. Similarly, small commercial customers see limited electricity use outside of workday hours. Residential and small commercial customers also typically use a predominate portion of annual natural gas requirements during winter heating months and especially during the coldest peak send-out day on a natural gas system.

Q. How do these usage behaviors differ from large industrial customers?

A. Large industrial customers utilize electricity and natural gas within industrial processes with little weather sensitive loads. Thus, industrial loads tend to be more evenly distributed across the hours of the day, and throughout the year, depending upon plant or facility operations. Since these loads are not weather sensitive, there are usually limited differences between industrial summer and winter usage patterns. These customer classes are typically viewed as having high load factors, with peak energy demands relatively consistent to average daily and annual energy demands. This differs from residential customers, which tend to have lower load factors given the wide differences between their average and peak loads.

Q. Please define what is meant by a "load factor."

A. A load factor is defined as the ratio of the average load in kilowatt hours supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by taking the energy used during a period and dividing by the product of the maximum demand and the number of hours in the period.

$$Annual\ Load\ Factor = {}^{Annual\ kWh\ Energy\ Use}\!/_{(Peak\ kW\ Use * 8760\ Hours)}$$

A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity to meet the relatively large swings in load between average and peak periods.

Q. Is it preferable to promote the development of higher load factors?

A. Yes, as higher load factors are indicative of more efficient utilization of system resources. However, it should be recognized that all utilities inherently have customers with different load profiles due to differences in how the customer uses electricity. Furthermore, the development of integrated wholesale bulk electricity transmission systems has allowed utilities to collectively diversify generation resources and individual system demands, which has reduced the impact of individual system load characteristics on generation needs in recent years. While rates should recognize and promote the efficient utilization of utility system resources, one should caution against placing too much emphasis on this principle rewarding high load factor industrial customers to the detriment of low load factor residential and small commercial customers.

Q. Can utilities face incentives to allocate costs away from higher use/higher load factor customers?

A. Yes. Higher use/higher load factor customers such as industrial customers are inherently more price sensitive than lower use customers due to the relative impact increases in rates can have on these customers' total utility bills and the margins of produced goods. These higher-use industrial customers tend to have more energy supply alternatives that can include fuel switching and self-generation which is part of the reason why they are more price sensitive. Thus, utilities can have incentives to assign cost and revenue responsibilities away from larger price sensitive customers and onto those with fewer alternatives such as the residential and smaller commercial customer classes.

Q. What is a potential manner in which a CCOSS can be biased against lower load-factor customers?

A. Utilities by their nature are capital intensive industries with high degrees of capital expenditures required to develop systems to generate and transmit power or distributed natural gas throughput to customers relative to annual expenses associated with administrative operations. Therefore, deciding the appropriate definition and assignment of costs associated with utility capital investments (e.g., utility "plant in service") largely affects the cost of providing service. Utilities can often over-emphasize peak demand factors in allocating these large plant costs in order to assign more costs away from their more price sensitive customers.

Likewise, utilities can emphasize non-diversified single CP demands, NCP demands, individual customer demands, and peak sendout throughput in allocating costs associated with transmission and high voltage distribution plant facilities or distribution main facilities to favor high-load factor customers relative to low-load factor customers. Finally, utilities can over-emphasize customer connection aspects of lower voltage distribution facilities to favor high-use customers relative to low-use customers.

B. PSE's Electric CCOSS

Q. Have you prepared a summary of the results of the Company's electric CCOSS?

A. Yes, and this summary is presented as Exhibit DED-3. The Company finds that it earned a system average rate of return during the test year of 1.85 percent. The Company also finds that class-based rate of return ranges from -8.81 percent for the primary service irrigation customer class, to 14.95 percent for the retail wheeling class. The Company's test year residential class returns are estimated to be 1.60 percent.

Q. Do you disagree with any of the assumptions or allocation factors incorporated in the Company's proposed CCOSS?

A. Yes. The Company's CCOSS has one inconsistency regarding the classification of generation plant. I believe this incorrect classification leads to the Company overstating the class peak contribution relative to annual energy use.

Q. What functions do generation facilities serve?

A. Generation units are designed to serve both energy and demand/capacity needs of a utility. The exact degree of this split between energy and demand functionality depends on the individual generator in question and its place in the utility's dispatch curve. Generators defined as baseload units are designed with low operating costs in mind and are thus designed to operate during most hours of the year. Generators defined as peaking units, on the other hand, are designed with additional operational flexibility relative to baseload units in mind, specifically in the ability of the units to quickly and cost effectively "start-up." Peaking units are typically held in reserve and only utilized by a utility during periods of peak demand when the utility requires additional generation resources not required during lower demand periods. These functional differences impact the function the generator provides to a utility's energy system, with generators defined as baseload serving more of a utility system's energy needs, while generators defined as peaking units serve more of the utility's demand/capacity needs. It is therefore not uncommon to develop composite energy and demand allocators that represent this mixed use and classification. Furthermore, it is not uncommon to use hybrid demand and energy cost allocation methods to account for this dual function.

Q. Please describe the Company's allocation of generation plant.

A. The Company allocates generation plant using the Renewable Future Peak Credit (RFPC) methodology,[1] as promulgated in Commission rule by

[1] Direct Testimony of Christopher T. Mickelson, Exh. CTM-1T at 18:10–13.

WAC 480-85-060.[2] The Company's RFPC model results in 70 percent of generation plant costs being classified as demand related and 30 percent of generation plant costs being allocated as energy-related.[3]

Q. Please describe the RFPC methodology.

A. The RFPC methodology consists of an energy component and a demand component. The Company uses its 2023 Integrated Resource Plan (IRP) to estimate the cost of a hybrid renewable and storage resource (Effective Load Carrying Capacity or ELCC) comparable to Combined Cycle Gas Turbine (CCGT) generation on the Company's system.[4] The costs are divided into energy and demand-related components.[5] Storage is assumed to be demand-related and wind costs are primarily energy-related.[6] This methodology is, itself, an updated version of the Thermal Peak Credit allocation method, which dates back to the 1970s in Washington rate proceedings.[7]

Q. Please provide an overview of the thermal peak credit allocation methodology.

A. The Thermal Peak Credit allocation method is the predecessor to Washington's current RFPC methodology and is based upon an energy component and a demand component. Under this allocation approach, the demand component is calculated by dividing the cost of a demand resource (represented by the cost of a

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[2] WAC 480-85-060.
[3] Mickelson, Exh. CTM-1T at 20:5–7.
[4] *Id.* at 18:14–21.
[5] *Id.* at 18:21–19:1.
[6] *Id.* at 19:1–4.
[7] Peak Credit Methodology of Staff, *In re Amending WAC 480-07-510 and Adopting Chapter 480-85 WAC Relating to Cost of Serv. Studies for Elec. and Nat. Gas Investor-Owned Utils*., Docket UE-170002 (filed Mar. 5, 2018).

combustion turbine plant or "CT") by the cost of an energy resource (represented by a combined cycle turbine plant or "CCT"). The energy component, meanwhile, is equal to one minus the demand component. Collectively, these two components are represented via the following formulas:

$$Demand =$$

$$\left(\frac{1}{2}\right) CT\ Fixed + O\&M/kW\ CT \Big/ (CCT\ Fixed + O\&M) * C.F./\ kW\ CT$$

$$Energy = 1 - Demand$$[8]

Q. Is the Company's calculation of the energy and demand components consistent with the above approach?

A. No. The Company's renewable peak credit methodology represents an evolution of the historic thermal peak credit methodology to account for the differences in renewable generation resources compared to fossil-fuel driven thermal generation. Unlike when examining thermal generation units where the levelized cost of new generation capacity is less expensive than the levelized costs for new baseload units designed to provide inexpensive energy, renewable generation capacity resources such as battery energy storage are generally more expensive than inexpensive renewable energy resources such as wind farms and solar generation systems. However, the Company also calculates the demand component by dividing the cost of the demand resource (i.e. the storage resource) by the sum of the demand and energy resource costs. This is inconsistent with the above

[8] *Id*.

framework, which utilizes only energy within the denominator when determining the relative demand allocation.

Q. Does the Company's addition of energy and demand components within its calculation make logical sense?

A. No. The Company calculates the levelized cost of a Lithium-Ion battery as representing the costs of a new capacity asset, while the Company calculates the levelized costs of the Company's wind farm assets as representing the costs of a new energy asset.[9] Rather than estimating the relative levelized costs of a new energy storage battery asset to an inexpensive wind farm asset solely serving customer's energy needs, the Company estimates the cost of a new energy storage battery asset to the cost of **both** this energy storage battery asset and the aforementioned wind farm assets. The addition serves no logical purpose other than to incorrectly inflate the capacity component of the Company's calculation relative to the energy component.

Q. What impact does this inconsistency have upon the allocation of generation plant?

A. The Company's generation plant classification results in a demand component of 70 percent and an energy component of 30 percent. When this inconsistency is resolved, however, the demand component declines to 57 percent, and the energy component increases to 43 percent.

Q. Please summarize your CCOSS recommendation.

[9] Mickelson, Exh. CTM-1T at 16:19-21.

A. I recommend the Commission adopt the alternative generation plant classification methodology as is illustrated within my alternative CCOSS. This alternative methodology is consistent with the Commission's approved cost of service guidelines and simply corrects the Company's demand and energy allocators, while also providing for a more accurate representation of PSE's generation costs.

Q. Would your CCOSS recommendations change the class rates of return?

A. Yes. Using my recommended allocation factors, I have prepared an explanatory alternative CCOSS, which is attached to this testimony as Exhibit DED-4. It should be noted, however, that the alternative CCOSS presented in Exhibit DED-4 is independent of revenue requirement adjustments supported by other witnesses and is thus presented for explanatory purposes only.

IV. REVENUE DISTRIBUTION

A. Revenue Distribution Policy Objectives

Q. Please explain the purpose of the revenue distribution process in setting rates.

A. The revenue distribution process (which can also be called the "revenue spread" or "rate spread" process) allocates (or "spreads") a utility's overall revenue deficiency across customer classes, which in turn is used to establish a new set of retail rates to be applied prospectively. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. Does the revenue distribution process include any policy considerations?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis could result in outcomes inconsistent with Commission policies, including situations leading to adverse rate impacts for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a broad set of ratemaking policy goals.

Q. What are those broader ratemaking policy goals?

A. There are several generally accepted ratemaking principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.
- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.

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Q. How are the above principles applied in developing an appropriate rate spread for a regulated utility?

A. Regulators often consider all, or many of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. What factors has the commission historically relied upon in the determination of an appropriate rate spread?

A. The Commission has historically considered a multitude of factors, including the cost of service, fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[10] Out of all these factors, rate parity, i.e. the relationship between revenues and costs, seems to be most heavily relied upon within the Commission's review and determination of rate spread proposals.[11]

Q. Please explain the concept of a parity ratio.

A. The parity ratio refers to the relationship between a rate class's revenues and its costs. A parity ratio of 1.00 occurs in which a utility collects 100 percent of the revenue needed to cover the costs of serving the class. A parity ratio of 0.90, likewise, indicates that the utility collects 90 percent of the revenue needed to

[10] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-200900, Final Order, ¶ 328 (Sept. 27, 2021).
[11] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 and UG-190530 (*Consolidated*), Final Order, ¶ 516 (Jul. 8, 2020).

cover the costs of the customer class, and a parity ratio of 1.10 occurs when a utility collects 110 percent of the revenues required to serve the customer class.[12]

Q. What are acceptable parity ratios within the context of utility rate cases in Washington?

A. The Commission has previously provided the following guidance when applying the results of a CCOSS: "A COSS uses precise math to follow elaborate cost assignments. Commission practice considers the error or range of accuracy to be +/-0.05. In other words, COSS results within the range 0.95 to 1.05 are considered within the precision of the COSS."[13]

B. Company's Proposed Electric Revenue Distribution/Rate Spread

Q. Please explain how the Company proposes to distribute its electric class revenue requirements.

A. The Company is requesting an electric base rate revenue increase of $584 million in 2025 and $260 million in 2026,[14] and it proposes to use four distinct revenue distribution methodologies for such rate increases.[15] First, three customer classes are excluded from the parity analysis when distributing the revenue increases – special contract, retail wheeling, and firm resale. Instead, these customers receive calculated rate spreads to reach full parity and avoid cross-jurisdictional subsidy.[16] Second, the primary service irrigation customer

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[12] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Company*, Docket UE-152253, Final Order, at 74–75, (Sept. 1, 2016).
[13] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-152253, Final Order, at 74 (Sept. 1, 2016).
[14] Direct Testimony of Susan E. Free, Exh. SEF-1T at 40:12–41:12.
[15] Mickelson, Exh. CTM-1T at 26:1–8.
[16] *Id.* at 26:9–13.

class is given a change equal to 150 percent of the total system increase as this class is estimated to be more than 20 percent below full parity.[17] Third, the high voltage service customer class is given a change equal to 90 percent of the total system increase as this class is estimated to be more than 5 percent above full parity.[18] Finally, the company allocates the remaining revenue increase equally across the remaining classes which include residential service, the general service classes, primary service–general and schools, and lighting service.

Q. What are the results of the Company's proposed revenue distribution?

A. Exhibit DED-5 presents the Company's proposed rate increase and relative rate of return (Relative ROR or RROR) for each major rate class across each rate year, as well as on a cumulative basis. In 2025, residential service customers receive a 27.9 percent increase, which represents a RROR of 1.01. All secondary voltage general service classes, lighting service, primary voltage general service, and the schools class receive a similar base rate increase as residential resulting in 27 to 29 percent increases, which represent an RROR of between 0.98 to 1.05. The impacts across these classes differ slightly due to the varying revenue impact of the proposed Targeted Electrification Pilot program. The high voltage customers receive a lower 24.5 percent increase while irrigation customers receive a much higher 48.8 percent increase. This represents a RROR of 0.89 for the high voltage class and 1.77 for the irrigation class. In 2026, the revenue increase was distributed using the same allocation factors across the main customer classes.

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[17] *Id.* at 26:4–6.
[18] *Id.* at 26:3–4.

Residential customers receive a 10.8 percent increase, which represents a RROR of 1.04.

Q. What do you mean by a RROR?

A. A RROR effectively standardizes class-specific rates of return to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (i.e., there is no cross-subsidy). A RROR that is greater than one indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 can be said to be making a less-than-average contribution to the overall system and is effectively being partially subsidized by other classes.

C. Company's Proposed Natural Gas Revenue Distribution/Rate Spread

Q. Please explain how the Company proposes to distribute its natural gas class revenue requirements.

A. As shown in Exhibit DED-6, the Company proposes to distribute its natural gas class revenue requirement increase to customer classes on an ad-hoc basis based on the relevant parity ratios shown in its CCOSS results. First, the Company proposes to increase residential rates by 90 percent of the system average increase to reflect the Company's CCOSS finding of a current cost parity ratio for these customers of 1.10.[19] Second, the Company proposes to increase rates for the large volume class by 110 percent of the system average increase to reflect the Company's CCOSS finding of a current cost parity ratio for these customers of 0.94.[20] Third, the Company proposes to increase rates for the commercial and industrial and interruptible classes by 125 percent of the system average increase to reflect the Company's CCOSS finding of a current cost parity ratio for these classes of 0.81 and 0.85, respectively.[21] Fourth, the Company proposes to increase rates for non-exclusive interruptible customers by 150 percent of the system average increase based on the Company's CCOSS finding of a current cost parity ratio for these customers of 0.57.[22] Fifth, the Company proposes to increase rates for limited interruptible customers by 75 percent of the system average increase based on the Company's CCOSS finding of a current cost parity ratio for these customers of 1.31.[23] Finally the Company proposes to set rates for exclusive interruptible customers at full cost of service.[24]

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[19] Direct Testimony of John D. Taylor Exh. JDT-1T at 28, Table 2.
[20] *Id.*
[21] *Id.*
[22] *Id.*
[23] *Id.*
[24] Taylor, Exh. JDT-1T at 27:16.

D. Revenue Distribution Recommendations

Q. Do you agree with the Company's electric and natural gas revenue distribution proposals?

A. No. The Company's proposed electric and natural gas revenue distributions suffer from two major deficiencies. First, the Company's proposals are based on the results of faulty electric and natural gas CCOSS. Second, the Company's proposal would increase rates for specific customer classes by 1.5 times the system average rate increase, which is inconsistent with the concept of rate gradualism.

Q. What is your recommendation regarding the Company's proposed electric revenue distribution?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative electric CCOSS results that also limits the rate increase to any single customer class to 1.15 times the overall electric system average increase. Using the Company's proposed electric system average increase of 27.6 percent, my recommendation would reduce the maximum total base revenue increase of any single rate class to 31.7 percent, compared to the Company's proposed maximum rate increase of 48.8 percent. Exceptions to this rule are made for customer classes with unique considerations such as special contract, retail wheeling, lighting service, and firm resale.

Q. Have you prepared a summary of the effects of your proposed electric revenue distribution?

A. Yes. Exhibit DED-7 presents an illustrative summary of the effects of my proposed electric revenue distribution under the Company's proposed system average rate increase for year 1 of 27.6 percent. My proposed electric revenue distribution would limit the increase to irrigation customers by applying a 31.7 percent increase in year 1, equal to 1.15 times the overall average. This adjustment to the Company's irrigation proposal would be offset by increasing the Company's other customer class increases in year 1 by an additional 0.01 percent. In year 2, Exhibit DED-7 allocates the proposed increase equally to all customer classes (with the exception of classes with unique considerations noted earlier). The cumulative increase to base rates for the residential class under the proposed electric revenue distribution is 39.7 percent, consistent with the Company's proposal.

Q. What is your recommendation regarding the Company's proposed natural gas revenue distribution?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method that limits the rate increase to any single customer class to 1.25 times the overall natural gas system average increase. Using the Company's proposed natural gas system average increase of 51.5 percent over two years, my recommendation would reduce the maximum total base revenue increase of any single rate class to 64.3 percent, compared to the Company's proposed maximum rate increase of 77.2 percent. I also recommend the Commission increase the revenue allocation to Large Volume customers to 1.15 times the system average to reflect this class' current revenue-to-cost ratio below parity and hold exclusive interruptible rates constant, rather than decreasing rates as proposed by the Company.

Q. Have you prepared a summary of the effects of your proposed natural gas revenue distribution?

A. Yes. Exhibit DED-8 presents an illustrative summary of the effects of my proposed natural gas revenue distribution under the Company's proposed base system average rate increase across two rate years of 51.5 percent. My proposed natural gas revenue distribution would increase base rates for the residential class by 46.2 percent, compared to the Company's proposal which would increase such rates by 46.3 percent. This is a reduction in proposed increase of $0.3 million.

V. RATE DESIGN

A. Rate Design Objectives

Q. How are electric utility rates typically structured?

A. Electric utility rates are typically comprised of three basic elements. The first element is the fixed monthly customer charge, sometimes referred to as a basic service charge or a basic facility charge. The second is the energy-based component that is a volumetric rate applied toward a customer's monthly energy usage during a billing period, often measured in terms of kilowatt-hour (kWh). Finally, demand rates are surcharges that are assessed based upon a customer's maximum usage during a billing period, commonly measured in terms of kilowatt (kW) for those customers that are demand metered. Historically, some smaller use customer classes, such as residential and small commercial classes, are not demand-metered and thus, only pay customer and energy charges. Customers with just customer and energy charges have bills that are based upon what is commonly called a "two-part tariff" (e.g., energy and customer charge) whereas large demand metered customers face a "three-part tariff" (e.g., energy, customer, and demand charges).

Q. How are natural gas rates typically structured?

A. Natural gas utility rates are likewise typically comprised of three elements. The first component is the fixed monthly customer charge. The second is the energy-based component that is a volumetric rate applied toward a customer's monthly energy usage during a billing period, often measured in terms of therms or dekatherms (Dth). Finally, demand rates are surcharges that are assessed based upon a customer's maximum usage during a billing period. As with electric rate design, some smaller use customer classes, such as residential and small general services classes are not demand-metered and thus, only face customer and energy charges in what is commonly called a "two-part tariff." Larger, demand metered, customers face a "three-part tariff" which includes a customer, volumetric, and demand charge. A "multi-part tariff" is a term often used to generalize a set of rates that have various combinations of both fixed (customer charge) and variable charges (energy and/or demand charges).

Q. How should policy balance cost assignments between fixed customer charges and volumetric rates?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by the two-part and three-part tariff form that is sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. What is the appropriate role of costs in setting rates for a multi-part tariff?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates to be set optimally (i.e., fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed costs" philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a multipart tariff typically has more to do with consumer demand than it does with cost in both an electric and natural gas context given the capital-intensive nature of public utilities.

Q. Does the rate design process have any goals?

A. Yes. The development of utility rates, or "rate design" often has a few goals. For example, rates are sometimes designed to send certain price signals to consumers in order to influence their usage decisions.[25] Sometimes, rate design becomes a balancing act since rates must be designed to be both supply-eliciting (i.e., assist utilities in financing of capital investments) and demand-inhibiting (i.e., inhibit the growth in demand that generates the need for capital investments).[26]

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[25] Bonbright, James et. al., *Principles of Pub. Util. Rates,* Pub. Utils. R., Inc., Second Ed.*,* at 96–97.
[26] *Id.*

B. Basic Residential Customer Charge

Q. Please provide an overview of the Company's basic residential electric customer charge proposal.

A. The Company is proposing to increase the basic charge in rate year 1 for electric residential customers from $7.49 to $9.74 per month,[27]with an additional $2.92 increase proposed for rate year 2, increases the total basic charge to residential customers to $12.66 across both rate years.[28] This represents an increase of 30 percent per rate year.

Q. Please provide an overview of the Company's basic natural gas residential customer charge proposal.

A. Similar to the Company's proposed increase in residential natural gas customer charges, the Company proposes to increase monthly customer charges for natural gas rates by up to 30 percent.[29] This includes proposals for an increase in residential schedule 23 and 53 basic charges of 18.9 percent in each proposed rate year.[30] This results in a cumulative proposed increase in basic residential natural gas customer charge $5.17 per month, from the current $12.50 to a proposed $17.67 per month.[31]

Q. What is the basis of the Company's proposed electric residential customer charge increase?

[27] Mickelson, Exh. CTM-1T at 39:18–19.
[28] Mickelson, Exh. CTM-6.
[29] Taylor, Exh. JDT-1T at 29:9–10.
[30] Taylor, Exh. JDT-5.
[31] *Id.*

A. The Company claims that the proposed increase in basic charge will cause customers to pay a dollar amount that reflects the fixed costs incurred, irrespective of their consumption level.[32] The Company states that "this is crucial for reducing cross-subsidization . . . the increase delivers accurate signals to both high- and low-usage customers, promoting energy efficiency and providing guidance on optimal grid utilization."[33] The Company also argues that having a higher customer charge minimizes the influence that weather conditions can have and also promotes predictability and stability in regards to financial budgeting.[34]

Q. What is the basis of the Company's proposed natural gas residential customer charge increase?

A. The Company claims its proposed increase in residential natural gas customer charge will realign pricing components for existing customer classes by moving towards the unit cost to serve.[35]

Q. Have you prepared an analysis of costs commonly associated with electric and natural gas customer charges?

A. Yes. Exhibits DED-11 and DED-12 present an analysis of current customer charges with customer-related expenses for the Company's electric and natural gas units, respectively. "Customer-related" expense accounts for both electric and natural gas utilities are those typically allocated on the basis of customers and can include: removing and setting meters; maintenance of meters; natural gas services

[32] Mickelson, Exh. CTM-1T at 31:3–9.
[33] *Id* at 13-17.
[34] *Id* at 32:3–14.
[35] Taylor, Exh. JDT-1T at 29:8–13.

and electric service drop expenses; maintenance of natural gas services and electric service drops; meter reading expenses; customer records and collections; customer billing and account; customer service and information expenses; and sales expenses. These costs can also include the depreciation expense associated with service/service drop and meter plant accounts, as well as the carrying charges (at the Company's requested rate of return) on these plant accounts.

Q. What are your findings regarding the Company's electric customer-related costs?

A. Exhibit DED-11 shows that the Company's existing electric basic service charges are in excess of estimated electric customer-related costs for all customer classes. This includes the residential service class, where the current $7.49 per month basic service charge recovers 124.4 percent of the estimated $6.02 monthly customer-related costs.

Q. What are your findings regarding the Company's natural gas customer-related costs?

A. Exhibit DED-12 shows that the Company's proposed natural gas basic service charges are in excess of estimated natural gas customer-related costs for most customer classes. This includes the residential service class, which is estimated to have customer-related costs of $9.59 per month, compared to the Company's current $12.50 per month customer charge.

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Q. Have you developed an analysis of residential electric customer charges across the region?

A. Yes. This analysis, presented in Exhibit DED-13, compares the Company's electric residential customer charge to other regional electric utilities. This analysis demonstrates that the Company's current residential customer charge of $7.49 per month is below the average residential customer charge of $11.06 for other regional utilities. However, the Company does not have the lowest residential customer charge in the region, with NorthWestern Energy LLC in Montana significantly reduced electric customer charges of $4.20. The Company's proposed increase to a $12.66 monthly residential customer charge would be greater than all other Washington investor-owned utilities and above the regional average.

Q. Have you developed an alternative analysis of residential natural gas customer charge across the region?

A. Yes. This analysis, presented in Exhibit DED-14, compares the Company's natural gas general service customer charge to other regional natural gas utilities. This analysis demonstrates that the Company's current residential customer charge of $12.5 per month is above the average residential customer charge of $10.14 for other regional utilities. The Company's proposed increase to a $17.67 monthly residential customer charge would result in the highest residential customer charge in the region.

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Q. Are higher basic service charges consistent with the promotion of energy efficiency and conservation?

A. No. The Company's proposal is inconsistent with the promotion of energy efficiency and conservation in Washington for the simple reason that it places more costs into the fixed component of rates than in the variable component. This reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. Have other commissions recognized the detrimental effect increased fixed charges have on energy efficiency?

A. Yes. In rejecting a request by Baltimore Gas and Electric to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission (MPSC) recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[36]

Q. Is the Maryland Commission alone in its belief that high fixed charges discourage efficient use of energy?

[36] Md. Pub. Serv. Comm'n Case No. 9299*, In re Baltimore Gas and Electric Co. for Adjustment in its Electric and Gas Base Rates.*, Order No. 85374 at 99, (Md. Pub. Serv. Comm'n, Feb. 22, 2013).

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners (NARUC) lists Straight-Fixed Variable (SFV) rate design as an alternative to delink utility revenue from sales. An SFV attaches all fixed-related costs to fixed charges while relegating only variable charges to volumetric rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume</u>.[37]

Q. Has any national public policy analysis noted the efficiency disincentives associated with SFV-type rate designs?

A. Yes. The National Action Plan for Energy Efficiency (NAPEE), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such

[37] *Decoupling for Electric & Gas Utils.: Frequently Asked Questions (FAQ)* (Sept. 2007), Grants & Research Depart., Nat'l Ass'n of Reg. Util. Comm'rs, at 5. (Emphasis added).

disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. <u>While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies</u>. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[38]

Q. Have studies shown a relationship between income and electricity usage?

A. Yes. Exhibit DED-15 reflects household energy expenditure data for the Pacific census region as recorded in the 2020 Residential Energy Consumption Survey (RECS) performed by the U.S. Energy Information Administration (EIA). The data indicate household income is positively correlated with energy consumption: as household income increases, energy consumption increases. For example, households earning less than $20,000 a year consume nearly 25 percent less energy per year than households earning greater than $140,000 a year. This means that the customer charge is a higher proportion of a lower income household's total bill than a higher income household's energy bill. It therefore follows that the impact of increases to the customer charge creates a disproportionately adverse impact on lower income households, thereby raising rate equity concerns.

[38] Nat'l Action Plan for Energy Efficiency, *Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design* at 13–14, prepared by William Prindle, ICF International, Inc. (Sept. 2009) (Emphasis added).

Q. Have you prepared typical electric bill analyses associated with the Company's rate design proposals?

A. Yes. Exhibit DED-16 illustrates electric bill changes for residential customers of varying monthly kWh usage levels. This analysis shows that low-use residential customers would see their bill increase by 19.84 percent, relative to the proposed average rate increase for all residential customers of 17.45 percent.

Q. Have you prepared typical natural gas bill analyses associated with the Company's rate design proposals?

A. Yes. Exhibit DED-17 illustrates natural gas distribution bill changes for residential customers of varying monthly therm usage levels. This analysis shows that low-use residential customers would see their bill increase by 24.08 percent, relative to the proposed average rate increase for all residential customers of 19.70 percent.

Q. Is the understanding that an increase in natural gas basic service charges will affect low-income customers consistent with the Company's findings?

A. Yes. While the Company argues that higher basic service charges will not negatively impact low-income electric customers, it acknowledges that its proposed higher basic service charges for natural gas customers will negatively impact low-income natural gas customers as low-income natural gas users on its system typically use less natural gas per month than average customers. Specifically, the Company found that low-income residential natural gas customers consume 53 therms of natural gas per month compared to the average residential monthly natural gas use of 66 therms per month.[39]

Q. Are there general concerns related to the Company's proposal for significant increases in its monthly electric and natural gas customer charges?

A. Yes. One of the reasons for approving higher customer charges is to provide utilities with a level of revenue certainty regardless of monthly customer usage, thus partially immunizing a utility from potentially negative impacts on the recovery of fixed costs from falling customer usage. However, the Commission should recognize that both the Company's electric and natural gas operational units have decoupling mechanisms in place which allow the Company to recover revenues associated with decreases in customer usage. The proposed increases in monthly electric and natural gas customer charges would be duplicative of current policy in Washington which has permitted decoupling for the Company's electric and natural gas operational units.

C. Basic Residential Customer Charge Recommendations

Q. What is your recommendation regarding the Company's residential electric basic service charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in residential customer charges for a number of reasons. First, the Company's proposal is based upon an inaccurate accounting of customer-related costs. Second, the Company's proposed $12.66 per month residential electric customer charge will be 14.5 percent higher than the regional average. Third, the

[39] Miller, Exh. JMD-1T at 40:6–16.

Company's proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. Finally, the Company's proposed increase in customer charges is unnecessary to provide revenue certainty as PSE's electric operational utility has a decoupling mechanism in place with allows the utility to reconcile rates for changes in customer electric usage.

Q. What is your recommendation regarding the Company's general service natural gas basic service charge proposal?

A. Similar to my recommendation regarding the Company's proposed increase in electric basic service charges, I recommend that the Commission reject the Company's proposed increase in general service customer charges (which includes residential customers) for a number of reasons. First, the Company's proposed $17.67 per month residential natural gas customer charge will be 74.2 percent higher than the regional average. Second, the Company's proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. Finally, the Company's proposed increase in customer charges is unnecessary to provide revenue certainty as PSE's electric operational utility has a decoupling mechanism in place with allows the utility to reconcile rates for changes in customer electric usage.

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VI. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your electric CCOSS recommendation.

A. I recommend the Commission adopt an alternative generation plant classification methodology that corrects the Company's faulty RFPC calculation. My recommendations are consistent with the Commission's approved cost of service guidelines and simply corrects the Company's demand and energy allocators, while also providing for a more accurate representation of PSE's generation costs.

Q. What is your recommendation regarding the Company's proposed electric revenue distribution?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative electric CCOSS results that also limits the first-year rate increase to any single customer class to 1.15 times the overall electric system average increase. Using the Company's proposed electric system average increase of 27.6 percent, my recommendation would reduce the maximum total base revenue increase of any single rate class to 31.7 percent, compared to the Company's proposed maximum rate increase of 48.8 percent.

Q. What is your recommendation regarding the Company's proposed natural gas revenue distribution?

A. I recommend the Commission adopt a more reasonable revenue distribution allocation method that limits the rate increase to any single customer class to 1.25 times the overall natural gas system average increase. Using the Company's proposed natural gas system average increase of 51.5 percent over two years, my recommendation would reduce the maximum total base revenue increase of any single rate class to 64.3 percent, compared to the Company's proposed maximum rate increase of 77.2 percent. I also recommend the Commission increase the revenue allocation to Large Volume customers to 1.15 times the system average to reflect this class' current revenue-to-cost ratio below parity and hold exclusive interruptible rates constant, rather than decreasing rates as proposed by the Company.

Q. What is your recommendation regarding the Company's residential electric basic service charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in residential customer charges for a number of reasons. First, the Company's customer charge proposal is based upon an inaccurate accounting of customer-related costs, and a correct accounting shows that the current customer charge recovers all customer-related costs. Second, the Company's proposed $12.66 per month residential electric customer charge will be 18.1 percent higher than the regional average. Third, the Company's proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. Finally, the Company's proposed increase in customer charges is unnecessary to provide revenue certainty since PSE has an electric decoupling mechanism in place with allows it to reconcile differences between test year RPC and those RPCs realized between rate cases.

Q. What is your recommendation regarding the Company's general service natural gas basic service charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in general service customer charges (which includes residential customers) for several reasons. First, the Company's proposed $17.67 per month residential natural gas customer charge will be 74.2 percent higher than the regional average, and the highest residential customer charge in the region. Second, the Company's proposal would negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. Finally, the Company's proposed increase in customer charges is unnecessary to provide revenue certainty since PSE also has a revenue decoupling mechanism in place for its gas operations

Q. Does this conclude your testimony?

A. Yes.