Exhibit No. AZA-1T
Dockets UE-220066|UG-220067|UG-210918
Witness: Ali Al-Jabir

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-220066 and UG-220067 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility	DOCKET UG-210918

RESPONSE TESTIMONY AND EXHIBITS OF ALI AL-JABIR

ON BEHALF OF

THE FEDERAL EXECUTIVE AGENCIES

July 28, 2022

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ali Al-Jabir. My business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411.

Q. WHAT IS YOUR OCCUPATION?

A. I am an energy advisor and an Associate in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit No. AZA-2.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies ("FEA"). Our firm is under contract with The United States Department of the Navy ("Navy") to perform cost of service, rate design and related studies. The Navy represents the Department of Defense and all other Federal Executive Agencies in this proceeding. The FEA is one of the largest consumers of electricity in the service territory of Puget Sound Energy ("PSE" or "the Company") and takes electric service from the Company primarily on Schedule 49.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony focuses on certain aspects of PSE's proposed electric revenue requirement, class cost of service and rate design. Specifically, my testimony addresses the following areas:

- The classification and allocation of electric generation fixed costs;
- The classification and allocation of electric wheeling expenses in FERC Account 565;
- The class allocation of electric distribution poles and wires costs;
- The class allocation of any changes in electric base rate revenues approved in this case; and
- The rate design of the Colstrip and the multi-year rate plan riders.

The fact that I am not addressing other issues in the Company's application in this proceeding should not be construed as an endorsement of the Company's position with regard to such issues.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations can be summarized as follows:

1. The Washington Utilities and Transportation Commission ("WUTC" or "the Commission") conducted a generic cost of service proceeding that resulted in the adoption of certain methods for the functionalization, classification and allocation of electric and natural gas costs by utilities in Washington. However, these cost allocation rules also allow alternative allocation methodologies to be proposed, provided that each modification is explained in testimony and the party shows that the proposed modification improves the cost of service study and is in the public interest. Therefore, it is my understanding that the Commission has provided latitude for parties to propose cost allocation methodologies that differ from the methods in the generic rule. In light of this, I am proposing certain cost allocation methods in my testimony that deviate from the Commission's generic rule.

2. PSE proposed a renewable future peak credit allocation method for fixed electric generation costs. PSE's proposed allocation method would allocate a portion of generation fixed costs on an energy rather than a demand basis. However, electric generation capital costs are fixed, sunk costs that do not vary with the amount of energy consumed by customers. Economic principles dictate that such fixed, sunk costs should be allocated entirely on a demand basis.

3. PSE's production fixed costs should be classified as entirely demand-related. These costs should be allocated to the customer classes exclusively based on those classes' contribution to the

utility system peaks in the four highest coincident peak demand months of the test year used to develop the class allocators in the electric class cost of service study ("CCOSS"). Specifically, the allocation factor should be developed using the class contribution to the utility system peaks that occurred in December 2020 and January, February and June of 2021 (the "4 CP method"). The 4 CP method provides a much better reflection of cost causation than classification or allocation methods that utilize energy usage to any significant degree.

4. PSE proposes to classify and to allocate the costs in FERC Account 565 (Transmission of Electricity by Others) on an energy basis. This is inconsistent with

the Commission's cost of service methodology rules, which specify that such wheeling expenses should be classified and allocated on a demand basis. The wheeling of electricity over the transmission grid is enabled by the existence of the underlying transmission network, and the driver for the construction of the transmission grid is system coincident peak demands. Because the wheeling of electricity over the transmission grid is enabled by the fixed capital investment in the transmission system, it is appropriate to classify and to allocate the wheeling expenses in FERC Account 565 on a 12 CP demand basis, consistent with the Company's proposed allocation of other demand-related transmission costs in this proceeding.

5. The Company proposes to allocate the cost of electric distribution poles, conduit and wires based on the average of the twelve monthly distribution system noncoincident peaks ("12 NCP method") for primary system and secondary system customers together, using an average 12NCP - Primary & Secondary Voltage Only allocator. This proposed allocation method does not properly adhere to cost causation principles for two reasons. The first problem with the Company's proposal is that it allocates costs on a 12 NCP basis rather than a 1 NCP basis. Distribution poles and wires investments must be sized to meet the maximum localized NCP demands that customers impose on these facilities, regardless of when such maximum demands occur during the year. Consequently, it is inappropriate to average the twelve monthly NCPs in developing the allocator for these distribution fixed costs. Instead, it would be more appropriate to allocate these costs based on the single highest annual NCP for each class, separately for primary system and for secondary system customers, regardless of when these NCPs occur during the test year ("1 NCP method"). The second problem is that PSE did not differentiate the allocation of electric distribution poles and wires costs by voltage level (primary vs. secondary). The Company's approach is inconsistent with cost causation because it allocates a portion of secondary level distribution poles and wires costs to customers that take service at the primary voltage level. In fact, customers that take service at the primary service level do not use the Company's secondary voltage level poles and wires to take electric service from PSE. To correct this problem, distribution poles and wires costs should be allocated using two distinct allocators that differentiate between primary and secondary distribution voltage level customers. Correcting these two problems with the Company's proposed allocation method results in the application of a 1 NCP allocator for primary voltage level poles and wires costs (1 NCP – Primary Voltage) that includes the NCP demands of both primary and secondary voltage level customers, and a different allocator for secondary voltage level poles and wires costs (1 NCP – Secondary Voltage) that includes the NCP demands of only customers that take service at the secondary distribution level.

6. Through the discovery process, the FEA sought to collect distribution poles and wires data from PSE that was differentiated by voltage level of service. However,

the Company responded that it does not track these distribution poles and wires costs by voltage level. To address this issue, I recommend that the Commission require

PSE to track distribution poles and wires costs by voltage level on a going forward basis. The Commission should also require the Company to propose an electric CCOSS in its next general rate case that includes separate 1 NCP class cost allocators for distribution poles and wires costs at the primary and secondary voltage levels, respectively. In the absence of distribution poles and wires cost data that is differentiated by voltage level in the current proceeding, I recommend that the Commission require the Company to apply a single 1 NCP - Primary & Secondary Voltage Only allocator in the current rate case to allocate all distribution poles and wires costs on a 1 NCP basis rather than a 12 NCP basis, without differentiating the cost allocation by voltage level.

7. The electric revenue allocation and class rate design should be mainly driven by the goal of achieving cost-based rates.

8. The Company's electric revenue allocation proposal does not show sufficient movement toward cost-based rates for Rate 49.

9. To reduce cross subsidies among rate classes and to create greater movement towards cost-based rates, I recommend that the High Voltage class (Rates 46/49) be moved to full cost parity in this case. The revenue shortfall resulting from my modified electric base rate revenue allocation for Rates 46/49 should be prorated to the remaining customer classes based on the revenue allocation proposed by the Company in order to meet PSE's proposed total revenue requirement. Consistent with PSE's proposal, I directly assigned the revenue increase to the Special Contract, Choice/Retail Wheeling and Firm Resale classes. My revenue spread proposal results in minimal incremental rate increases to PSE's other electric customer classes.

10. PSE is proposing to recover all costs in the Colstrip and multi-year rate plan riders using per kWh energy charges. Given that the Company has classified and/or allocated only a small portion of these rider costs on an energy basis, it is inconsistent with cost causation to recover the entirety of the rider costs through per kWh energy charges. To be consistent with cost causation principles, the design of the rider charges should adhere as much as reasonably possible to the classification and allocation of the rider costs. Consequently, for customer classes whose base rate structures include demand charges, the Company should recover the rider costs that are classified as demand-related through demand charges and the recovery of rider costs through per kWh energy charges should be limited to those costs that are properly classified as energy-related.

<u>Rates Should Be Established Based On Class Cost of Service</u>

Q. PLEASE COMMENT ON THE BASIC PURPOSE OF A CLASS COST OF SERVICE STUDY.

A. After determining the total Company cost of service or revenue requirement, a CCOSS is used to allocate the revenue requirement or cost responsibility among the customer classes. A CCOSS compares the cost that each customer class imposes on the system to the revenues that each class contributes. For example, when a customer class produces the same rate of return as the total system rate of return, it is paying revenue to the utility just sufficient to cover the costs incurred in serving that class. If a class produces a below-average rate of return, it may be concluded that the revenues provided by the class are insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce a below system average rate of return. The CCOSS shows the cost to serve each rate class reflecting cost causation, as well as the rate of return from each class under current and proposed rates.

Q. HOW IS THE COST OF SERVING EACH CUSTOMER CLASS DETERMINED?

A. The appropriate mechanism to determine the cost of serving each customer class is a fully allocated embedded CCOSS. It follows, however, that the objective of cost-based rates cannot be attained unless the CCOSS is developed using cost-causation principles.

Q. WHY IS A CCOSS OF IMPORTANCE?

A. A CCOSS shows the costs that a utility incurs to serve each customer class. It is a widely held principle that costs should be allocated among customer classes on the basis of cost causation. The tenet that costs that cannot be directly assigned to a particular class should be allocated based on cost causation is perhaps the most universally accepted cost of service principle. The costs should be allocated to the classes on the basis of how or why those costs are incurred by the utility. The results of a CCOSS are used in assigning cost responsibilities to various customer classes in regulatory proceedings.

Q. SHOULD THE COST ALLOCATION AND RATE DESIGN PROCESS FOLLOW COST CAUSATION PRINCIPLES?

A. Yes. Rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs, but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

Q. PLEASE DESCRIBE THE PROPER FUNDAMENTALS OF A CCOSS.

A. Cost of service is a basic and fundamental ingredient in the ratemaking process. In all cost of service studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the cost causation principle.

The first step in a CCOSS is known as functionalization. This simply refers to the process by which the Company's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as <u>classification</u>. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related and customer-related costs in order to facilitate the allocation of costs applying the cost causation principles.

Demand- or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. For example, fuel expense is almost directly proportional to the amount of kilowatt-hours supplied by the utility system to meet its customers' energy requirements.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation and revenue accounting are considered customer-related costs.

The final step in the CCOSS is the allocation of each category of the functionalized and classified costs to the various customer classes using cost causation principles. Demand-related costs are allocated on a basis that gives recognition to each class's responsibility for the Company's need to build new assets to serve demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

Q. WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE REVENUE ALLOCATION AND RATE DESIGN PROCESS?

A. The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

Q. HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A. To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve them, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

Q. HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A. Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate, such as customer and demand charges, will result in a disproportionate share of revenues being collected from high energy consuming or high load factor customers and send erroneous price signals to all customers.

Q. HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A. Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on actual costs do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q. PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A. When rates are closely tied to costs, the impact on the utility's earnings due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power costs.

Q. ARE YOU AWARE THAT THE COMMISSION CONDUCTED A GENERIC COST OF SERVICE PROCEEDING THAT RESULTED IN THE ADOPTION OF A SET OF COST OF SERVICE METHODOLOGY RULES?

A. Yes. My understanding is that the generic cost of service proceeding resulted in the adoption of certain methods for the functionalization, classification and allocation of electric and natural gas costs by utilities in Washington. However, the rules also allow alternative allocation methodologies to be proposed, provided that each modification is explained in testimony and the party shows that the proposed modification improves the cost of service study and is in the public interest.[1/] In addition, the cost of service rules give the Commission the latitude to grant an exemption from the provisions of the rules.[2/] Indeed, PSE has proposed an energy allocation for FERC Account 565 wheeling expenses in this proceeding that deviates from the demand allocation specified in the

[1/] WAC 480-85-060(2).

[2/] WAC 480-85-070.

Commission's cost of service methodology rule. Therefore, it is my understanding that the Commission has provided latitude for parties to propose cost allocation methodologies that differ from the methods in the generic rule. In light of this, I am proposing certain cost allocation methods in my testimony that deviate from the Commission's generic rule.

Classification and Allocation of Generation Fixed Costs

Q. WHAT METHOD DID PSE USE TO CLASSIFY AND TO ALLOCATE FIXED PRODUCTION COSTS IN ITS ELECTRIC CCOSS TO THE CUSTOMER CLASSES?

A. PSE used the renewable future peak credit methodology to classify production costs into demand and energy components based on the cost of battery storage (demand) and a wind turbine (energy) derived from the Company's 2021 Integrated Resource Plan ("IRP"). The demand-related component of fixed production costs was allocated to the classes using a 12CP allocation factor. PSE allocated the energy-related component of fixed production costs based on class energy consumption. The Company states that this approach resulted in an 80% demand and a 20% energy peak credit allocation of generation fixed costs. PSE considered all variable generation costs to be 100% energy-related.[2/]

Q. ARE THESE COST CLASSIFICATION RESULTS REASONABLE IN LIGHT OF THE COST DRIVERS OF FIXED GENERATION INVESTMENT?

A. No. This classification is improper because the cost driver for fixed generation investments is the maximum coincident demand on the system, which dictates the design capacities of those resources. The amount of energy produced by those resources does not drive

2/ Prefiled Direct Testimony of Birud D. Jhaveri (Exhibit BDJ-1T) at p. 17.

the incurrence of fixed generation costs, which are properly classified as entirely demand-related.

Instead of applying the renewable future peak credit method, fixed production costs should be classified as 100% demand-related and allocated to the customer classes according to each class's demand during the system peak months of December 2020 and January, February and June of 2021. During the aforementioned months, PSE's production resources are likely to be in use and operating at or close to their maximum capacities. Other months of the year should be excluded from the development of the allocation factor because those months do not reflect the times of the year when generating units are likely to be used at their full capacity.

Q. WHY IS IT APPROPRIATE TO CLASSIFY AND TO ALLOCATE FIXED PRODUCTION COSTS ON A COINCIDENT PEAK DEMAND BASIS?

A. It is the Company's system peak demands that drive the need for additional generation capacity. Demands during moderate-load times, whether time of day or month of year, do not cause new generating capacity to be built because there is excess capacity on the system during those times.

Generation capital costs are fixed, sunk costs that do not vary with the amount of energy consumed by customers. Economic principles dictate that such fixed, sunk costs should be allocated on a demand basis. A coincident peak demand cost allocation method is consistent with cost causation principles because it recognizes the fact that generation capacity additions are driven by the growth in system peak demand and that these additions must be sized to meet the system peak demand. Therefore, a coincident peak demand allocation method properly reflects the cost drivers that lead to the construction of generation facilities and that determine the sizing of such incremental facilities. If rate design is properly aligned with cost allocation, a coincident peak demand-based method also sends appropriate signals to customers to modify their use of the system in order to minimize their contribution to the system peak demand and to therefore reduce or to defer the need for incremental generation capacity.

Q. WHY IS IT INAPPROPRIATE TO CLASSIFY AND TO ALLOCATE A PORTION OF FIXED PRODUCTION COSTS ON AN ENERGY BASIS?

A. It is the demand for power, not the energy flow itself that determines when additional generation capacity is needed. Moreover, the fixed and sunk nature of generation investment means that the cost, once incurred, does not vary with the amount of energy produced or consumed. Only variable costs that vary with the level of output of the units, such as fuel, should be classified as energy related and allocated on the basis of energy allocators. Therefore, PSE's proposal is inconsistent with sound cost causation principles.

Additionally, by weighting energy in the classification and allocation of production fixed costs, the renewable future peak credit method adversely impacts customer classes such as the High Voltage Class that have higher than average load factors. The beneficiaries of the peak credit method are customers with below-average load factors, such as residential customers. Because the peak credit method's partial reliance on an energy-based classification and allocation of costs is inconsistent with the cost drivers of fixed production investment, this benefit to the residential customers is in fact a subsidy that large, high load factor customers are forced to provide to smaller, lower load factor customers on the system. This class cross-subsidy is inconsistent with cost-based ratemaking principles.

Classifying a portion of production fixed costs on an energy basis unfairly increases the cost to customers that efficiently utilize a system such as high load factor and off-peak customers. High load factor and off-peak customers on electric utility systems allow for more efficient utilization of production plant, which benefits all customers on the system. Therefore, the renewable future peak credit method discourages the efficient use of the system by sending an inefficient price signal to customers that incorrectly suggests that all energy usage at any time of the year plays a role in incremental generation investment.

Q. WHAT ABOUT THE ARGUMENT THAT SOME PORTION OF THE INVESTMENT IN BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED ON THE THEORY THAT A UTILITY IS WILLING TO MAKE CERTAIN ADDITIONAL CAPITAL INVESTMENTS TO REDUCE ITS LEVEL OF FUEL COSTS?

A. With respect to this argument, the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average <u>total</u> costs. The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the fixed cost per kWh for base load plant is usually less than the fixed cost per kWh for the peaking plant. Of course, since the fuel costs of base load plants are lower than the fuel costs of peaking plants, the overall cost per kWh for base load plants is also less than the overall cost per kWh for peaking plants.

It is necessary, therefore, to look at both capital costs and operating costs in light of the expected capacity factor of the plant. The fact that base load plants have lower fuel costs than peaking plants does not mean that the investment in base load plants is strictly to achieve lower fuel costs. Investment in a base load plant would be made to achieve lower total costs, of which fixed costs and fuel costs are the primary ingredients. For any given utility system, the capital costs are not a function of the number of kWh generated, but are fixed and therefore are properly related to system demands, not to kWh sold. These costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. If sales volumes change, these costs are not affected, but continue to be incurred, making them fixed or demand-related in nature. Therefore, it is not proper to classify and to allocate a portion of the fixed costs related to production based on energy.

Q. WHAT CLASSIFICATION AND ALLOCATION METHOD DO YOU RECOMMEND FOR FIXED PRODUCTION INVESTMENT IN THIS CASE?

A. As I explained earlier in this response testimony, a utility incurs fixed production investment due to the need to meet the system peak demands of customers rather than customer energy usage. Therefore, PSE's production fixed costs should be classified as entirely demand-related and these costs should be allocated to the customer classes exclusively based on those classes' contribution to the utility system peaks in the four highest coincident peak demand months of the test year that was used to develop the class allocators in the electric class cost of service study ("CCOSS"). Specifically, the allocation factor should be developed using the class contribution to the utility system peaks that occurred in December 2020 and January, February and June of 2021 (the "4 CP method"). The 4 CP method provides a much better reflection of cost causation than classification or allocation methods that utilize energy usage to any significant degree. Although energy costs have some influence over the kind of generating unit that a utility builds to meet the system peak demand, it is the shrinking reserve margins over peak demand that cause new generation plant to be built. All variable fuel and purchased power costs should be allocated entirely on an energy basis.

Classification and Allocation of Wheeling Expenses

Q. HOW IS PSE PROPOSING TO CLASSIFY AND TO ALLOCATE ELECTRIC WHEELING EXPENSES IN THIS PROCEEDING?

A. PSE proposes to classify and to allocate the costs in FERC Account 565 (Transmission of Electricity by Others) on an energy basis.[3] This is inconsistent with the Commission's cost of service methodology rules, which specify that such wheeling expenses should be classified and allocated on a demand basis.[5]

Q. WHAT IS PSE'S RATIONALE FOR CLASSIFYING AND ALLOCATING WHEELING EXPENSES ON AN ENERGY BASIS?

A. The Company contends that these costs relate to the supply of energy and are not a cost that provides additional capacity to the PSE system.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ENERGY CLASSIFICATION AND ALLOCATION OF WHEELING EXPENSES?

A. No. The wheeling of electricity over the transmission grid is enabled by the existence of the underlying transmission network, and the driver for the construction of the transmission grid is system coincident peak demands. A demand allocation method recognizes the fact that transmission planning is based on ensuring that there is sufficient transmission capacity in place to meet the maximum simultaneous peak demand imposed by customers on the transmission system. A coincident peak allocation method properly recognizes this cost causative factor that gives rise to the incurrence of fixed transmission costs.

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[3] Prefiled Direct Testimony of Birud D. Jhaveri (Exhibit BDJ-1T) at p. 19.

[5] WAC 480-85-060(3).

In order to preserve system reliability, transmission facilities must be sized to meet the annual system peak demand, even if the actual system demand is much lower in most hours of the year. Therefore, growth in the system coincident peak demand is the trigger for bulk transmission additions and dictates the size of such additions. This means that customer demands at the time of the system peak demand intervals are the central driver for the incurrence of transmission investment costs.

An energy-based allocation method for transmission costs would inappropriately use variable energy consumption levels to allocate fixed and sunk transmission costs that do not vary with energy consumption. From an economic standpoint, it is more efficient and more consistent with cost causation to classify and to allocate fixed capital costs on a demand basis.

Because the wheeling of electricity over the transmission grid is enabled by the fixed capital investment in the transmission system, it is appropriate to classify and to allocate the wheeling expenses in FERC Account 565 on a 12 CP demand basis, consistent with the Company's proposed allocation of other demand-related transmission costs in this proceeding.

Allocation of Distribution Poles and Wires Costs

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COST ALLOCATION METHODS PROPOSED BY PSE IN THIS PROCEEDING?

A. Yes. I disagree with the Company's proposed cost allocation method for electric distribution poles and wires costs in FERC Accounts 364 and 365.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH PSE'S PROPOSED ALLOCATION OF DISTRIBUTION POLES AND WIRES COSTS.

A. The Company proposes to allocate the cost of distribution poles, conduit and wires based on the average of the twelve monthly distribution system non-coincident peaks ("12 NCP method") for primary system and secondary system customers together, using an average 12NCP - Primary & Secondary Voltage Only allocator.[4/] This proposed allocation method does not properly adhere to cost causation principles.

Distribution poles and wires investments are electrically close to the customer. Therefore, these investments must be sized to meet the maximum localized NCP demands that customers impose on these facilities, regardless of when such maximum demands occur during the year. Consequently, it is inappropriate to average the twelve monthly NCPs in developing the allocator for distribution fixed costs. Instead, it would be more appropriate to allocate these costs based on the single highest annual NCP for each class, separately for primary system and for secondary system customers, regardless of when these NCPs occur during the test year ("1 NCP method").

The 1 NCP approach appropriately recognizes that PSE must plan its local distribution system to meet the highest localized demands that customers impose on the system, irrespective of when those highest demands occur during the year. The lower NCP demands that occur during other months of the year do not drive the amount of required investment in these localized facilities.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH PSE'S PROPOSED ALLOCATION OF DISTRIBUTION POLES AND WIRES COSTS?

A. Yes. PSE did not properly differentiate the allocation of distribution poles and wires costs by voltage level. The Company allocated these costs using an average 12NCP - Primary & Secondary Voltage Only allocator. This approach is inconsistent with cost causation because it allocates a portion of secondary level distribution poles and wires costs to

4/ Prefiled Direct Testimony of Birud D. Jhaveri (Exhibit BDJ-1T) at p. 22.

customers that take service at the primary voltage level. In fact, customers that take service at the primary service level do not use the Company's secondary voltage level poles and wires to take electric service from PSE. Therefore, consistent with cost causation principles, primary service level customers should not be required to pay for distribution poles and wires that the Company constructs to serve customers at the secondary distribution level.

Q. HOW CAN THIS PROBLEM BE CORRECTED?

A. Distribution poles and wires costs should be allocated using two distinct allocators that differentiate between primary and secondary distribution voltage level customers. As discussed earlier in my testimony, each of the two allocators should rely on a 1 NCP rather than an average 12 NCP allocation method. This should result in the application of a 1 NCP allocator for primary voltage level poles and wires costs (1 NCP – Primary Voltage) that includes the NCP demands of both primary and secondary voltage level customers, and a different allocator for secondary voltage level poles and wires costs (1 NCP – Secondary Voltage) that includes the NCP demands of only customers that take service at the secondary distribution level. The 1 NCP – Secondary Voltage allocator would exclude the NCP demands of primary voltage level customers to ensure that primary voltage level customers do not pay for lower voltage distribution facilities that they do not use.

Q. WERE YOU ABLE TO MODIFY THE COMPANY'S ELECTRIC CCOSS TO APPLY SEPARATE ALLOCATORS FOR DISTRIBUTION POLES AND WIRES COSTS THAT ARE DIFFERENTIATED BY PRIMARY AND SECONDARY VOLTAGE LEVELS OF SERVICE?

A. No. Through the discovery process, the FEA sought to collect distribution poles and wires data from PSE that was differentiated by voltage level of service. However, the

Company responded that it does not track these distribution poles and wires costs by voltage level.[5/] In the absence of this data, I was unable to develop separate class cost allocators for the Company's distribution poles and wires costs at the primary and secondary voltage levels, respectively.

Q. WHAT IS YOUR RECOMMENDATION TO CORRECT THIS PROBLEM?

A. I recommend that the Commission require PSE to track distribution poles and wires costs by voltage level on a going forward basis. The Commission should also require the Company to propose an electric CCOSS in its next general rate case that includes separate class cost allocators for distribution poles and wires costs at the primary and secondary voltage levels, respectively.

Q. HAVE YOU DEVELOPED A REVISED ELECTRIC COSS THAT IMPLEMENTS THE MODIFIED CLASS COST ALLOCATION METHODS THAT YOU ARE RECOMMENDING?

A. Yes. I have developed a revised electric CCOSS that applies a 4 CP allocator for generation fixed costs as opposed to the renewable future peak credit method, a 12 CP demand allocator rather than an energy allocator for wheeling costs and a 1 NCP allocator rather than a 12 NCP allocator for distribution poles and wires costs. As discussed earlier in my testimony, I was unable to develop separate allocators for distribution poles and wires costs by voltage level due to PSE's inability to provide the required data.

The customer class revenue parity ratios that result from my proposed alternative electric CCOSS allocation methods are summarized in Exhibit No. AZA-3. This exhibit also compares the class parity ratios using my recommended class allocation methods to the parity ratios that result from the Company's electric COSS proposal, which relies

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[5/] PSE's response to FEA data request nos. 22 and 23.

on the renewable future peak credit method to classify and to allocate fixed production costs in this case.

Q. WHAT ARE THE IMPLICATIONS OF THE PARITY RATIOS THAT RESULT FROM THE APPLICATION OF THE ALTERNATIVE COST ALLOCATION METHODS THAT YOU ARE RECOMMENDING?

A. Under my recommended electric CCOSS, the revenue parity ratio for the High Voltage class (Schedules 46 and 49) increases significantly from 1.16 under the Company's proposed electric CCOSS to 1.26. Any class parity ratio in excess of 1.0 means that the customer class is paying rates in excess of its cost of service. Therefore, the implications of the parity ratios shown in Exhibit No. AZA-3 are two-fold. First, the Schedule 49 parity ratio of 1.16 under the Company's electric CCOSS proposal demonstrates that Schedule 49 is paying rates in excess of its cost of service when class cost responsibility is determined using the Company's renewable future peak credit allocation method.

The second implication is that the flawed peak credit allocation method proposed by the Company is masking the true extent of the subsidy that Schedule 49 is providing to other customers on the system. When this flawed allocation method is corrected to reflect a 4 CP cost allocation method that is more consistent with cost causation, the extent of the subsidy provided by Schedule 49 increases dramatically to a parity ratio of 1.26. The large size of this subsidy merits strong corrective action in this proceeding to move Schedule 49 to rates that reflect the class's actual cost of service.

<u>**Electric Revenue Allocation**</u>

Q. WHAT SHOULD BE THE PRINCIPAL CONSIDERATION IN DEVELOPING THE REVENUE ALLOCATION AND CLASS RATE DESIGN IN THIS PROCEEDING?

A. For the reasons described earlier in my direct testimony, the revenue allocation and class rate design should be mainly driven by the goal of achieving cost-based rates.

Q. HAVE YOU REVIEWED THE RESULTS OF THE COMPANY'S ELECTRIC CCOSS?

A. Yes. The results of the electric CCOSS are summarized in Exhibit No. AZA-4. This exhibit shows the CCOSS results at present and proposed rates under the Company's cost study. The CCOSS results include the rate of return, the relative rate of return index, and the revenue under- or over-collection based on each class's rate of return.

Q. HOW CAN THE CCOSS RESULTS BE INTERPRETED WITH RESPECT TO THE REVENUE CONTRIBUTION OF EACH CLASS RELATIVE TO ITS COST OF SERVICE?

A. The rates of a customer class are set at cost of service when the relative rate of return index of the class is 100. At that level, the rate of return derived from the class is equal to the system rate of return. A customer class has a revenue under-collection when the revenues provided through its rates are less than the cost to serve that class, resulting in a class relative rate of return index below 100. Conversely, a customer class has a revenue over-collection when the revenues collected from the class are greater than the cost to serve that class, resulting in a relative rate of return index greater than 100.

Q. HOW DOES THE COMPANY PROPOSE TO DISTRIBUTE THE PROPOSED BASE RATE ELECTRIC REVENUE DECREASE AMONG THE CUSTOMER CLASSES?

A. The Company's filing in this proceeding would result in an electric base rate revenue reduction. However, PSE's proposal results in an overall electric revenue increase when the revenue impact of the Company's proposed riders is included.

Exhibit No. AZA-5 shows in columns (3) and (4) the Company's proposed electric base rate revenue decrease by amount and as a percentage of present revenue for each customer class. For comparison purposes, the exhibit also shows in columns (6) and (7) the class base rate decreases that would result from my electric revenue distribution proposal in this proceeding. Exhibit AZA-6 provides a similar comparison between PSE's proposed revenue spread and my electric revenue spread proposal, but in this case, the results are provided on a total electric class revenue basis (including rider revenues) rather than on a base rate revenue basis to show the resulting total electric rate increases by customer class.

Q. WHAT CRITERIA DID THE COMPANY APPLY TO DISTRIBUTE THE PROPOSED ELECTRIC BASE REVENUE DECREASE IN THIS PROCEEDING AMONG THE CUSTOMER CLASSES?

A. PSE proposes to apply, with three exceptions, 100% of the adjusted system average base rate decrease to retail customer classes that are within 5% of full revenue parity. Rate classes that are more than 5% but less than 10% above full parity would receive a rate decrease that is 125% of the adjusted average decrease (All Electric Schools). Rate classes that are more than 10% above full parity would receive a base rate decrease that is 150% of the adjusted average base rate decrease (the High Voltage class). The Company proposes no rate change for the class that is 20% or more below full parity (Primary Voltage Irrigation and Pumping). Under the Company's proposal, the revenue deficiency for the Choice/Retail Wheeling and Special Contract classes is directly assigned to the applicable rate schedules based on the cost of service. The Company also proposes to move the Firm Resale/Special Contract class to full parity[6/]

6/ Prefiled Direct Testimony of Birud D. Jhaveri (Exhibit BDJ-1T) at p. 26-27.

Q. HOW DOES THE COMPANY'S BASE REVENUE ALLOCATION PROPOSAL IMPACT THE LEVEL OF COST SUBSIDY IMPOSED ON RATE 49?

A. At present rates, the High Voltage class is at a parity ratio of 1.16 based on the Company's electric CCOSS, which means that this class is providing a significant subsidy to other classes. PSE's electric revenue spread proposal would modestly reduce the parity ratio for the High Voltage class to 1.15. Therefore, PSE's proposal results in minimal movement towards cost-based rates for Rate 49.

Q. IS THE COMPANY'S ELECTRIC REVENUE ALLOCATION PROPOSAL REASONABLE IN YOUR OPINION?

A. No. The Company's proposal does not show sufficient movement toward cost-based rates and does not adequately correct the subsidies that Rate 49 customers are required to provide to other customer classes.

Q. ARE THERE ANY OTHER CONSIDERATIONS THAT MAGNIFY YOUR CONCERNS WITH THE COMPANY'S REVENUE ALLOCATION PROPOSAL FOR THE HIGH VOLTAGE CLASS?

A. Yes. The Company's electric CCOSS is based on the application of the renewable future peak credit method for the allocation of fixed production investment. As I explained earlier in this response testimony, this allocation method allocates excessive costs to Rate 49 relative to a truly cost-based allocation methodology. Even using the flawed renewable future peak credit cost allocation method, the Company's electric CCOSS study shows that Schedule 49 has a revenue parity ratio of 1.16, meaning that it is being required to pay rates that are in excess of its cost of service. If the flawed renewable future peak credit allocation approach is corrected to apply a more appropriate 4 CP cost allocation method for generation fixed costs, Exhibit No. AZA-3 shows that the parity ratio for Schedule 49 would increase significantly to 1.26 under the 4 CP method. This demonstrates that, when one applies a more reasonable allocation approach for fixed production investment, Rate 49 is in fact providing a much larger subsidy to other classes relative to the Company's analysis. This excessive subsidy is clearly unreasonable and it merits more aggressive action to move Rate 49 toward cost-based rates relative to the Company's proposal.

Q. BASED ON YOUR ANALYSIS, ARE YOU PROPOSING ANY MODIFICATIONS TO THE COMPANY'S ELECTRIC REVENUE ALLOCATION PROPOSAL?

A. Yes. To reduce cross subsidies among the rate classes and to create greater movement towards cost-based rates, I recommend that the High Voltage class be moved to cost-based rates with a parity ratio of 1.0 in this proceeding. Under my proposal, the revenue shortfall resulting from my modified revenue allocation for the High Voltage class would be prorated to the other electric customer classes based on the revenue allocation proposed by the Company in order to meet PSE's proposed total electric revenue requirement. The exception to this approach is that I followed PSE's proposal to directly assign the revenue increase to the Special Contract, Choice/Retail Wheeling and Firm Resale classes.

Q. WOULD YOUR ELECTRIC REVENUE ALLOCATION PROPOSAL RESULT IN EXCESSIVE RATE IMPACTS ON OTHER CUSTOMER CLASSES?

A. No. As shown in Exhibit AZA-6, my proposed revenue allocation would result in a minimal incremental total electric rate increase of less than 0.5% to the other electric customer classes (including the residential and small commercial classes) relative to the Company's proposed revenue spread. For example, the proposed total electric rate increase to the residential class under PSE's proposal is 13.3%. By contrast, the residential class electric rate increase rises modestly to 13.56% under my proposed electric revenue spread.

<u>Rate Design of the Colstrip and Multi-Year Rate Plan Riders</u>

Q. PLEASE SUMMARIZE THE RATE DESIGN PROPOSED BY THE COMPANY FOR THE COLSTRIP RIDER.

A. PSE is proposing to recover all costs in the Colstrip and multi-year rate plan riders using per kWh energy charges.

Q. IS THE COMPANY'S PROPOSAL CONSISTENT WITH COST CAUSATION PRINCIPLES?

A. No. In response to discovery, the Company stated that it has classified 80% of the Colstrip rider costs as demand and only 20% as energy.[7] PSE also states that it classified the multi-year rate plan rider costs as 90.73% demand, 3.68% customer and only 5.59% energy.[10] Moreover, the Colstrip rider costs were allocated using the 80% demand/20% energy weighted allocation factor, while the multi-year rate plan rider costs were allocated using the rate base allocator from the Company's electric COSS.

Given the Company has classified and/or allocated only a small portion of these rider costs on an energy basis, it is inconsistent with cost causation to recover the entirety of the rider costs through per kWh energy charges. To be consistent with cost causation principles, the design of the rider charges should adhere as much as reasonably possible to the classification and allocation of the rider costs. Were these rider costs to be recovered through base rates, cost causation principles would dictate that the Colstrip

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[7] PSE's response to FEA data request no. 17.

[10] PSE's response to FEA data request no. 18.

and multi-year rate plan rider costs would be recovered as part of the base rate demand and energy charges of the customer classes, consistent with the classification of the underlying costs. The nature of these costs does not change simply because the costs are recovered through riders rather than through base rates.

Q. HOW CAN THE RATE DESIGN OF THE COLSTRIP AND MULTI-YEAR RATE PLAN RIDERS BE MODIFIED TO MORE ACCURATELY FOLLOW COST CAUSATION PRINCIPLES?

A. For customer classes whose base rate structures include demand charges, the Company should recover the rider costs that are classified as demand-related through demand charges and the recovery of rider costs through per kWh energy charges should be limited to those costs that are properly classified as energy-related.

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes, it does.

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