BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-190529 and UG-190530 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferral Accounting and Ratemaking Treatment For Short-life UT/Technology Investment	DOCKETS UE-190274 and UG-190275 (*consolidated*)

RESPONSE TESTIMONY AND EXHIBITS OF ALI AL-JABIR

ON BEHALF OF

THE FEDERAL EXECUTIVE AGENCIES

November 22, 2019

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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 and transmission fixed costs;
- The allocation of any changes in electric base rate revenues approved in this case;
- PSE's proposal to implement an attrition adjustment; and

- The Company's proposed Conjunctive Demand Service Option Pilot ("Conjunctive Demand Pilot").

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 Commission should reject PSE's proposal to update the peak credit analysis using more recent proxy generation resource data. The Company's proposal would reduce the demand-related classification of production and transmission fixed costs from 25% to 11%. The energy-related classification of these costs would increase from 75% to 89%.

2. Generation and transmission 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. By reducing the demand-related component of production and transmission fixed costs, the Company's proposal to update the peak credit classification assumptions would further deviate from sound, cost-based ratemaking principles.

3. PSE's production and transmission 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 months of January, February, November and December 2018 (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. If the Commission believes that it is appropriate to use energy usage (as measured by average demand) to classify and to allocate a portion of fixed production and transmission costs in this proceeding, a more appropriate and reasonable approach would be to rely on the "average and excess demand" method. Specifically, I recommend applying the average and excess 4 non-coincident peak demand ("A&E 4 NCP") method to allocate production and transmission plant costs to the customer classes using factors that combine the classes' average demands and non-coincident peak demands. By linking the energy component of the class allocation factors to the system load factor, the A&E 4 NCP method provides a more reasonable energy weighting of fixed production and transmission costs that is more reflective of the actual operating characteristics of the Company's system relative to the peak credit method. Therefore, the A&E 4 NCP method is a more reasonable and balanced

allocation approach relative to the Company's proposal for continued reliance on the peak credit method in this case.

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

6. The Company's electric revenue allocation proposal does not show sufficient movement toward cost-based rates and excessively subsidizes residential customers. Moreover, PSE's proposed revenue allocation would inappropriately impose significant rate increases on customer classes that should receive a rate reduction if cost-based rates were applied.

7. To reduce cross subsidies among rate classes and to create greater movement towards cost-based rates, I recommend that no electric customer class receive a rate increase if it would be entitled to a rate reduction under cost-based rates. This means that Schedules 24, 25, 26, 31 and 46/49 should be maintained at their present rates and should receive no rate increase in this proceeding. In other respects, it is reasonable to maintain the revenue allocation approach applied by the Company.

8. I recommend that the Commission approve an electric revenue allocation that assigns no base rate increase to Schedules 24, 25, 26, 31 and 46/49. Under my proposal, the revenue shortfall resulting from my modified revenue allocation for Schedules 24, 25, 26, 31 and 46/49 is prorated to the Residential, Primary Voltage (Schedule 35), Primary Service (Schedule 43) and Lighting classes based on the revenue allocation proposed by the Company in order to meet PSE's proposed total electric revenue requirement. Consistent with PSE's proposal, I directly assigned the revenue increase to the Retail Wheeling, Special Contract and Firm Resale classes.

9. The Commission should reject PSE's proposal to establish an attrition adjustment in this proceeding. Such an adjustment would dilute the Company's incentive to control costs under the traditional ratemaking process and would transfer excessive risks to PSE's customers. Moreover, an attrition adjustment is unnecessary in light of the numerous opportunities that PSE currently has to recover cost escalations beyond historical test year levels.

10. If PSE experiences significant cost escalations in the future, it can file an application with the Commission to adjust its base rates in a full general rate case proceeding. This approach would provide the Company with a reasonable opportunity to recover prudently incurred cost increases, while ensuring that the Commission and impacted parties have an adequate opportunity to comprehensively review the prudence of the Company's costs based on actual historical data, rather than applying an attrition adjustment that relies on uncertain cost projections to set rates.

11. The Commission should approve the Company's proposed Conjunctive Demand Service Option Pilot. The conjunctive demand pilot will give customers with

multiple locations across PSE's service an opportunity to manage their power costs more effectively. At the same time, the pilot will benefit all customers on the Company's system by providing program participants with more efficient, cost-based price signals to control their maximum simultaneous demands in a manner that will help to reduce incremental generation and transmission investment on the Company's system.

12. After PSE has gained some experience with conjunctive billing through the Conjunctive Demand Pilot, the Company should expand the scope of the conjunctive billing program to other rate schedules, such as Schedule 49, that contain customers with multiple electricity accounts or locations.

Classification & Allocation of Generation & Transmission Fixed Costs

Q. PLEASE COMMENT ON THE BASIC PURPOSE OF A CLASS COST OF SERVICE STUDY ("CCOSS").

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 classification. 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 kilowatthours 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 HAS AN OPEN GENERIC COST OF SERVICE PROCEEDING?

A. Yes. My understanding is that the generic cost of service proceeding remains ongoing and that the Commission continues to seek comment from stakeholders on cost of service issues in that proceeding. Thus, it is unclear when, or whether, the Commission will arrive at a generic resolution of electric cost of service issues in a timely manner that would help inform the cost of service analysis in this proceeding.

Q. IN LIGHT OF THIS, HOW SHOULD RATES BE SET IN THIS CASE?

A. As I discussed earlier in my response testimony, rates should be set based on an informed analysis of the cost to serve each customer class. Accordingly, for the Commission to properly set rates in this case, it should have the best estimate of the class cost of service. The fact that a generic cost of service proceeding is ongoing does not obviate the need for a reasonable cost of the service determination in this case, especially considering that this case could conclude and rates could be set well before the conclusion of the generic cost of service proceeding.

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

A. PSE used the peak credit methodology to divide production costs into demand and energy components based on the ratio of the cost of a proxy peaking generating resource to the cost of a proxy base load generating resource. The numerator and the denominator of the ratio are expressed in $/kW-year. However, costs of the proxy units that are used to establish the ratio include variable costs such as fuel costs, variable operations & maintenance costs and emissions costs.

The demand-related component of fixed production and transmission costs was allocated to the classes using a 4CP allocation factor, which is based on each class's contribution to the Company's system peak demand during the months of January, February, November and December 2018. PSE allocated the energy-related component of fixed production and transmission costs based on class energy consumption.

Q. WHAT SPECIFIC CLASSIFICATION OF FIXED PRODUCTION AND TRANSMISSION COSTS DID THE COMPANY USE IN ITS ELECTRIC CCOSS?

A. PSE classified 11% of fixed production and transmission costs as demand-related and 89% as energy-related.

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

A. No. This classification is improper because the cost driver for fixed generation and transmission plant 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 the incurrence of fixed generation and transmission costs, which are properly classified as entirely demand-related.

Instead of applying the peak credit method, fixed production and transmission 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 January, February, November and December 2018. During the aforementioned months, PSE's production and transmission resources are likely to be in use and operating at or close to their maximum capacities.

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

A. It is the Company's system peak demands, which occur during the winter months that drive the need for additional generation and transmission 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 and transmission 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 and transmission 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 and transmission 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 and transmission capacity.

Q. WHY IS IT INCORRECT TO CLASSIFY AND ALLOCATE THE VAST MAJORITY OF FIXED PRODUCTION AND TRANSMISSION COSTS ON AN ENERGY BASIS, AS PSE IS PROPOSING?

A. It is the demand for power, not the energy flow itself that determines when additional generation and transmission capacity is needed. Moreover, the fixed and sunk nature of generation and transmission 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.

Moreover, by heavily weighting energy in the classification and allocation of production and transmission fixed costs, the peak credit method adversely impacts customer classes such as the High Voltage Class with 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 heavy reliance on an energy-based classification and allocation of costs is inconsistent with the cost drivers of fixed production and transmission 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 the bulk of production and transmission 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 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 and transmission 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 allocate a portion of the fixed costs related to production and transmission based on energy.

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

A. As I explained earlier in my response testimony, a utility incurs fixed production and transmission investment due to the need to meet the system peak demands of customers rather than customer energy usage. Therefore, these costs should be classified and allocated to the customer classes exclusively based on those classes' contribution to the utility system peaks in the months of January, February, November and December 2018 (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 and transmission plant to be built. All variable fuel and purchased power costs should be allocated entirely on an energy basis.

Q. IF THE COMMISSION DOES NOT ADOPT THE 4 CP METHOD, IS THERE AN ALTERNATIVE APPROACH FOR THE CLASSIFICATION AND ALLOCATION OF FIXED PRODUCTION AND TRANSMISSION COSTS THAT YOU WOULD RECOMMEND?

A. Yes. As explained above, I believe that the 4 CP allocation method is the optimal approach for the Company and the one that is most consistent with cost causation principles. However, if the Commission believes that it is appropriate to use energy usage (as measured by average demand) to classify and to allocate a portion of fixed production and transmission costs in this proceeding, a more appropriate and reasonable approach would be to rely on the "average and excess demand" method.[1/] Specifically, I would recommend applying the average and excess 4 non-coincident peak demand ("A&E 4 NCP") method to allocate production and transmission plant costs to the customer classes using factors that combine the classes' average demands and non-coincident peak demands. Under this approach, a customer class's allocation factor for fixed production and transmission costs would consist of two components. The first component (the average demand factor) is determined using average demand (energy consumption) times the system load factor. The second component of the class

[1/] See NARUC Manual at 49-52.

allocation factor (the excess demand factor) is determined as the proportion of the difference between the sum of the classes' 4 non-coincident peaks and the system average demand.[2]

By linking the energy component of the class allocation factors to the system load factor, the A&E 4 NCP method provides for a more reasonable energy weighting of fixed production and transmission costs that is more reflective of the actual operating characteristics of the Company's system relative to the peak credit method. Therefore, the A&E 4 NCP method is a more reasonable and balanced allocation approach relative to the Company's proposal for continued reliance on the peak credit method in this case.

Applying the A&E 4 NCP method in this proceeding results in allocating 62.6% of fixed production and transmission costs on an energy basis and 37.4% of these costs on a demand basis. While any allocation of fixed production and transmission investment on an energy basis is inappropriate, the A&E 4 NCP method places a greater weight on the role that customer demands play in PSE's incurrence of fixed production and transmission costs relative to the peak credit method that the Company proposes. As such, the A&E 4 NCP method is a more balanced approach that yields cost allocation results that are more consistent with cost causation principles relative to PSE's peak credit method.

Q. HAVE YOU DEVELOPED ELECTRIC CCOSS THAT REFLECT THE USE OF THE 4 CP AND A&E 4 NCP METHODS FOR THE ALLOCATION OF FIXED PRODUCTION AND TRANSMISSION COSTS?

A. Yes. The customer class revenue parity ratios that result from these alternative electric CCOSS are summarized in Exhibit No. AZA-3. This exhibit also compares the class

[2] *Id.*

parity ratios using these alternative allocation methods to the parity ratios that result from the Company's proposal to rely on the peak credit method to classify and to allocate fixed production and transmission costs in this case. The parity ratios are based on PSE's supplemental filing in this proceeding.

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 both the 4 CP and A&E 4 NCP methods, the revenue parity ratio for the High Voltage class (Schedules 46 and 49) increases significantly from 1.05 under the Company's proposed electric CCOSS to 1.13 under the A&E 4 NCP approach and 1.27 under the 4 CP approach, respectively. 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 1.05 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 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 or A&E 4 NCP cost allocation method that is more consistent with cost causation, the extent of the subsidy provided by Schedule 49 increases dramatically. The large size of this subsidy merits strong corrective action in this proceeding to move Schedule 49 closer to rates that reflect the class's actual cost of service.

Electric Revenue Allocation

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 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, based on PSE's supplemental filing in this case. 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 ELECTRIC REVENUE INCREASE AMONG THE CUSTOMER CLASSES?

A. Exhibit No. AZA-5 shows in columns (2) and (3) the Company's proposed revenue increase by amount and as a percentage of present revenue for each customer class, based on PSE's supplemental filing in this case. For comparison purposes, the exhibit also shows in columns (4) and (5) the rate increases that would result from my electric revenue distribution proposal in this proceeding.

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

A. PSE proposes to apply 100% of the adjusted system average rate increase 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 increase that is 75% of the adjusted average increase. Rate classes that are below full parity and that fall within a parity ratio bandwidth of 0.89 to 0.95 would receive 125% of the adjusted system average increase. Rate classes that are below full parity and have a parity ratio of less than 0.89 would receive 150% of the adjusted average increase. The adjusted average rate increase calculated by the Company accounts for the effect of above-average and below-average increases to certain classes. Under the Company's proposal, the revenue deficiency for the Retail Wheeling, Special Contract and Firm Resale classes is directly assigned to the applicable rate schedules.[3/]

Q. HOW DOES THE COMPANY'S REVENUE ALLOCATION PROPOSAL IMPACT THE LEVEL OF COST SUBSIDIES AMONG THE RATE CLASSES?

A. The major impact of the revenue allocation proposal is to reduce the rate increase for the residential rate class below the cost-based level. As shown on line 1 of Exhibit No. AZA-4, the Company proposes a base rate revenue subsidy of $47.3 million for the residential class under its proposed electric rates. This subsidy is financed by several

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[3/] Docket Nos. UE-190529 and UG-190530, PSE's Response to FEA Data Request No. 18.

other rate classes on PSE's system, including Schedule 49, through rates that exceed their fully allocated class cost of service.

The other significant impact of the Company's revenue allocation proposal is that it would impose a rate increase on several rate classes that should receive a rate reduction under cost-based rates. This result is shown in Exhibit Nos. AZA-4 and AZA-5. For example, line 9 of Exhibit No. AZA-4 shows that the High Voltage class (Schedules 46/49) is paying rates that exceed its cost of service by $2.2 million at present rates. However, under the Company's proposal, this class would receive a rate increase of $2.3 million or 5.76%, as shown on line 9 of Exhibit No. AZA-5. A similar pattern applies to each of the three secondary voltage level classes (Schedules 24, 25, and 26) and to the Primary Voltage (Schedule 31) class under PSE's proposed electric revenue distribution.

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 excessively subsidizes residential customers. Moreover, it is inappropriate to impose rate increases on customer classes that should receive a rate reduction if cost-based rates were applied.

Q. ARE THERE ANY OTHER CONSIDERATIONS THAT MAGNIFY YOUR CONCERNS WITH THE COMPANY'S REVENUE ALLOCATION PROPOSAL FOR SCHEDULE 49?

A. Yes. The Company's electric CCOSS is based on the application of the peak credit method for the allocation of fixed production and transmission investment. As I explained earlier in my response testimony, this allocation method allocates excessive costs to the high load factor classes such as Schedule 49 relative to a truly cost-based allocation methodology. Even using the flawed peak credit cost allocation method, the Company's electric CCOSS study shows that Schedule 49 has a revenue parity ratio of 1.05, meaning that it is being required to pay rates that are in excess of its cost of service. If the flawed peak credit allocation approach is corrected to apply a more appropriate 4 CP or A&E 4 NCP allocation method, Exhibit No. AZA-3 shows that the parity ratio for Schedule 49 would increase significantly to either 1.13 under the A&E 4 NCP method or to 1.27 under the 4 CP method. This demonstrates that, when one applies a more reasonable allocation approach for fixed production and transmission investment, Schedule 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 Schedule 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 no class receive a rate increase if it would be entitled to a rate reduction under cost-based rates. This means that Schedules 24, 25, 26, 31 and 46/49 should be maintained at their present rates and should receive no rate increase in this proceeding. In other respects, it is reasonable to maintain the revenue allocation method applied by the Company.

Q. HAVE YOU PREPARED A MODIFIED ELECTRIC REVENUE ALLOCATION THAT REFLECTS YOUR RECOMMENDATION?

A. Yes. Exhibit No. AZA-5, columns (4) and (5) shows my recommended electric revenue allocation, based on the requested revenue increase contained in PSE's supplemental filing in this case. As can be seen in the exhibit, my recommended revenue allocation imposes no rate increase on customer classes that should receive a rate reduction under cost-based rates (Schedules 24, 25, 26, 31 and 46/49). Under my proposal, the revenue shortfall resulting from my modified revenue allocation for Schedules 24, 25, 26, 31 and 46/49 is prorated to the Residential, Primary Voltage (Schedule 35), Primary Service (Schedule 43) and Lighting classes based on the revenue allocation proposed by the Company in order to meet PSE's proposed total electric revenue requirement. I also followed PSE's proposal by directly assigning the revenue increase to the Retail Wheeling, Special Contract and Firm Resale classes.

Attrition Adjustment

Q. PLEASE SUMMARIZE PSE'S PROPOSAL TO IMPLEMENT AN ATTRITION ADJUSTMENT IN THIS PROCEEDING.

A. PSE asks the Commission to approve an attrition adjustment to its electric and natural gas revenue requirements that would allow the Company to recover amounts in excess of the revenue requirement levels supported by its cost of service for the historical test year ending December 31, 2018. The Company's attrition study starts with historical cost data taken from PSE's latest eleven Commission Basis Reports ("CBRs") to develop regression analyses that PSE used to develop growth factors for the Company's costs. These growth factors were applied to base amounts for various cost line items to determine projected rate year values for these costs. The Company used these projected costs to develop an electric attrition revenue deficiency that includes projected rate year costs as estimated by the Company. The Company separately calculated projected costs for specific cost items where it determined that the nature or magnitude of the cost was outside of PSE's historical trend as reflected in the CBRs. The Company states that the corrected revenue amount of its proposed attrition request (prior to adjustment) is approximately $47.7 million for its electric operations and $30.2 million for its natural gas operations. [4/]

Q. IS IT REASONABLE TO AUTHORIZE AN ATTRITION ADJUSTMENT FOR PSE IN THIS PROCEEDING?

A. No. The attrition adjustment proposed by PSE would fail to adequately protect ratepayers because it allows the Company to increase rates today based on projections of costs that may or may not materialize in the future. This creates the risk that ratepayers will pay excessive costs through regulated rates if these cost increases do not materialize as projected by the Company. Absent the attrition adjustment, ratepayers would not be exposed to this risk.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COMPANY'S PROPOSED ATTRITION ADJUSTMENT?

A. Yes. An attrition adjustment would reduce the incentives that the Company has to control costs under the traditional ratemaking process. Under traditional ratemaking, PSE's base rates are set using a snapshot of costs and revenues for a historical test year, with pro forma adjustments. If the Company can reduce its costs relative to test year levels, the resulting profits flow directly to the utility's bottom line until base rates are reset in the next base rate case. This gives the Company a strong incentive to engage in cost cutting efforts and to enhance the efficiency of its operations.

By contrast, an attrition adjustment would essentially pre-approve the cost increases projected by the Company for the rate year for inclusion in its base rates.

4/ Docket Nos. UE-190529 and UG-190530, Prefiled Direct Testimony of Ronald J. Amen on behalf of Puget Sound Energy, June 20, 2019, pages 23-31 and PSE's First Revised Response to AWEC Data Request No. 20.

Absent the attrition adjustment, the Company would have an incentive to control cost escalations to levels below the growth factors incorporated into its attrition analysis in order to capture additional operating margins for the benefit of its shareholders. The attrition adjustment would undermine this incentive by granting the Company recovery of what are essentially pre-approved cost increases under the assumption that such cost increases are allegedly outside of the Company's ability to control. This would weaken the incentives for cost control that are inherent in the traditional utility ratemaking process and send a signal to the Company's management that there is little incentive to control costs below the projected levels incorporated into the attrition adjustment.

Q. PLEASE EXPLAIN WHY AN ATTRITION ADJUSTMENT DEPARTS FROM TRADITIONAL RATEMAKING PRINCIPLES.

A. Under the traditional ratemaking process, the Commission establishes the Company's revenue requirement in a base rate case by relying on a snapshot of the Company's costs and revenues for a given test year. The revenue levels are derived using the Company's test year sales levels, adjusted for weather and other known and measurable changes.

Once base rates are set to recover the allowed test year revenue requirement, these rates traditionally remain fixed until the next base rate case. The Company's shareholders bear the risk that earnings could be adversely impacted between base rate cases due to increases in costs or a reduction in revenues. Conversely, the Company's shareholders benefit if PSE can successfully reduce costs or increase revenues between base rate cases. This creates a powerful incentive for the Company's management to operate cost-effectively.

An attrition adjustment would alter the traditional ratemaking process by allowing the Company to adjust its base rates based on projections of rate year costs.

This undermines the strong incentives that PSE has to control costs between base rate cases by pre-approving cost escalations that the Company's management could potentially avoid through appropriate cost controls.

Q. WOULD AN ATTRITION ADJUSTMENT TRANSFER TRADITIONAL UTILITY BUSINESS RISKS FROM SHAREHOLDERS TO CUSTOMERS?

A. Yes. As I discussed above, the traditional base ratemaking process sets a utility's revenue requirement based on historical test year cost levels. This approach puts the Company's shareholders at risk for any cost escalations between rate cases. Under traditional ratemaking, such cost escalations are not recognized in the ratemaking process until the next base rate case.

An attrition adjustment would reduce this traditional business risk by incorporating estimates of future cost escalations into current base rates and it would therefore transfer some of this business risk to the Company's customers by requiring them to pay for such estimated cost escalations through base rates.

Q. SHOULD THE REGULATORY PROCESS IMMUNIZE THE UTILITY FROM BUSINESS RISK AND GUARANTEE THAT THE UTILITY WILL EARN ITS AUTHORIZED RATE OF RETURN?

A. No. The regulatory process should provide the utility with a reasonable opportunity to earn its authorized rate of return, provided that the utility manages its operations efficiently. Utility shareholders should continue to absorb traditional business risks, such as the risk of cost escalations between base rates cases, in order to provide the utility's management with adequate incentives to control its costs.

Q. ARE THE UTILITY'S SHAREHOLDERS COMPENSATED FOR BEARING THE RISK OF COST ESCALATIONS UNDER TRADITIONAL RATEMAKING?

A. Yes. Through the Company's allowed rate of return, the Company's shareholders are compensated for the business risks of operating the utility. Among these risks is the exposure to reduced operating margins due to cost escalations between base rate cases. Given this risk compensation through the rate of return, an attrition adjustment is unwarranted.

Q. DOES THE COMPANY CURRENTLY BENEFIT FROM REGULATORY MECHANISMS THAT EITHER INCORPORATE EXPECTED COST INCREASES INTO BASE RATES OR THAT TRANSFER THE RISK OF COST ESCALATIONS TO CUSTOMERS?

A. Yes. First, the Company has the opportunity to seek the Commission's approval of post-test year adjustments for known and measurable changes to its historical test year costs. Therefore, PSE already has an opportunity to include reasonably known and quantifiable increases to its historical costs through such post-year adjustments.

In addition, the Company benefits from numerous adjustment mechanisms that allow it to recover cost increases or to compensate for sales reductions between base rate cases. Examples of such adjustment mechanisms include the decoupling mechanism. In addition, the Company benefits from trackers and riders for numerous cost items, including conservation expenses, green power costs, municipal taxes, property taxes and others. In response to an FEA data request, the Company listed multiple riders and trackers designed to pass through costs to customers outside of a traditional base rate case.[5/]

[5/] Docket Nos. UE-190529 and UG-190530, PSE's Response to FEA Data Request No. 24(c).

Given these myriad opportunities that the Company already has to adjust its rates beyond historical test year levels to reflect cost escalations, approval of an attrition adjustment in this proceeding is unreasonable. In light of these other regulatory mechanisms that are already available to the Company to pass the risk of cost escalations to its customers, an attrition adjustment would excessively shield PSE's shareholders from business risks.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROPOSED ATTRITION ADJUSTMENT?

A. I recommend that the Commission reject PSE's request for an attrition adjustment. Such an adjustment would dilute the Company's incentive to control costs under the traditional ratemaking process and would transfer excessive risks to PSE's customers. Moreover, an attrition adjustment is unnecessary in light of the numerous opportunities that PSE currently has to recover cost escalations beyond historical test year levels.

If PSE experiences significant cost escalations in the future, it can file an application with the Commission to adjust its base rates in a full general rate case proceeding. This approach would provide the Company with a reasonable opportunity to recover prudently incurred cost increases, while ensuring that the Commission and impacted parties have an adequate opportunity to comprehensively review the prudence of the Company's costs based on actual historical data, rather than relying on uncertain cost projections to set rates.

Conjunctive Demand Service Option Pilot

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CONJUNCTIVE DEMAND SERVICE OPTION PILOT PROGRAM.

A. PSE proposes to implement a conjunctive demand pilot that would allow eligible customers to have their demands at multiple locations within the Company's service area be determined on a conjunctive basis for the purpose of billing electric power supply and transmission costs to such customers. This means that the customer's billing demand for electric power supply and transmission charges would be determined based on the highest hourly interval of demand across the customer's multiple locations participating in the pilot, as if the customer's multiple locations constituted a single load at a single location. The pilot would be open to customers taking electric service under PSE Schedules 26 or 31 who also possess meters capable of providing hourly interval meter reads. For customers who are not involved in the electrification of transportation, the Company proposes to limit pilot program participation to 50 participating locations. Pilot participation by any individual customer would be restricted to no more than five locations and to no more than two MW of maximum monthly billed demands across the participating locations in calendar year 2019. Total participation in the pilot program would also be limited to a maximum of 20 MW.[6/]

Q. IS IT APPROPRIATE TO ASSESS GENERATION AND TRANSMISSION DEMAND CHARGES TO CUSTOMERS WITH MULTIPLE LOCATIONS ON A CONJUNCTIVE BASIS?

A. Yes. A conjunctive billing approach appropriately recognizes the fact that the Company plans its generation and transmission system in a manner that recognizes demand diversity. This concept refers to the fact that not all customers or customer locations impose their maximum individual demands on PSE's system at the same time. Traditional billing approaches for generation and transmission costs ignore demand diversity by billing customers with multiple locations based on the sum of the individual

6/ Docket Nos. UE-190529 and UG-190530, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, June 20, 2019, pages 30-34.

maximum demands for each customer location on the utility's system, irrespective of the simultaneous peak demand that the customer imposes across its multiple locations.

Because generation and transmission investments constitute upstream facilities that are shared by all customers on the grid, utilities do not size such facilities based on the maximum demands of each customer or customer location on the grid, regardless of the time that such individual peak demands occur. Rather, system planners incorporate demand diversity into the planning process by sizing such shared facilities to meet the simultaneous system peak demands that customers impose on the system. If system planners were to ignore demand diversity in developing their generation and transmission expansion plans, utilities would overbuild their generation and transmission systems. This would require customers on the utility's system to pay excessive and unnecessary costs. Therefore, it is important to transition to billing systems for generation and transmission demand charges that more appropriately recognize demand diversity.

Q. WHAT ARE THE BENEFITS OF CONJUNCTIVE DEMAND BILLING RELATIVE TO TRADITIONAL REGULATED UTILITY BILLING METHODS?

A. As I explained above, conjunctive billing is more consistent with the manner in which utilities plan their generation and transmission systems and incur incremental generation and transmission plant costs relative to traditional billing methods. From the standpoint of system planning, it is the maximum simultaneous demand across multiple customer locations that drives investment in upstream generation and transmission facilities. Therefore, a conjunctive billing approach is more consistent with cost causation principles for generation and transmission investment.

From both a system planning and a cost causation perspective, conjunctive billing is more appropriate than traditional billing methods because it sends a better, cost-based signal that incents customers to manage and to control the simultaneous maximum demands that they impose on PSE's system across multiple locations. This benefits the pilot program participants by giving the participants an opportunity to control and to manage their electricity costs by coordinating their electricity demands across multiple locations. At the same time, it benefits all customers on the system by helping to reducing the rate of growth in the simultaneous peak demands that drive incremental generation and transmission investment. This price signal is absent under traditional billing practices that place equal weight on the maximum demand that each customer location imposes on PSE's system in isolation, regardless of the amount of demand diversity that the customer brings to the system.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO PSE'S PROPOSED CONJUNCTIVE DEMAND PILOT?

A. I recommend that the Commission approve the Company's proposed pilot program. The conjunctive demand pilot will give customers with multiple locations across PSE's service an opportunity to manage their power costs more effectively. At the same time, the pilot will benefit all customers on the Company's system by providing program participants with more efficient, cost-based price signals to control their maximum simultaneous demands in a manner that will help to reduce incremental generation and transmission investment on the Company's system.

After PSE has gained some experience with conjunctive billing through the pilot program, the Company should expand the scope of the conjunctive billing program to other rate schedules, such as Schedule 49, that contain customers with multiple electricity accounts or locations.

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes, it does.

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BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-190529 and UG-190530 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferral Accounting and Ratemaking Treatment For Short-life UT/Technology Investment	DOCKETS UE-190274 and UG-190275 (*consolidated*)

EXHIBIT AZA-2

QUALIFICATIONS OF ALI AL-JABIR

NOVEMBER 22, 2019

Qualifications of Ali Al-Jabir

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 AND BY WHOM ARE YOU EMPLOYED?

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

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I am a graduate of the University of Texas at Austin ("UT-Austin"). I hold the degrees of Bachelor of Arts and Master of Arts in Economics, both from UT-Austin. I have also completed course work at Harvard University. I received my B.A. degree with highest honors, and I am a member of the Phi Beta Kappa Honor Society.

Q. PLEASE STATE YOUR EXPERIENCE.

A. I joined BAI in January 1997. My work consists of preparing economic studies and economic policy analysis related to investor-owned, cooperative, and municipal utilities. Prior to joining BAI, I was employed at the Public Utility Commission of Texas ("Texas Commission") since 1991, where I held various positions including Policy Advisor to the Chairman. As Policy Advisor, I advised the Chairman on policy decisions in numerous rate and rulemaking proceedings. In 1995, I advised the Texas Legislature on the development of the statutory framework for wholesale competition in the Electric Reliability Council of Texas ("ERCOT"), and I was involved in subsequent rulemakings at the Texas Commission to implement wholesale open access transmission service in the region.

During my tenure at the Texas Commission and in my present capacity, I have reviewed and analyzed several electric utility base rate and fuel filings in Texas. I have also worked on utility rate, fuel, and merger proceedings and rulemakings in Virginia, Missouri, Colorado, Indiana, Alberta, Pennsylvania, North Carolina, South Carolina, Michigan and Nova Scotia. In addition to my work on such proceedings, I have drafted policy papers, comments and affidavits regarding electric industry restructuring, competitive policy and market design issues in Texas, Alabama, Louisiana, Georgia, and Delaware, as well as before the Federal Energy Regulatory Commission. I have been an invited speaker at several electric utility industry conferences, and I have presented seminars on utility regulation and industry restructuring.

BAI and its predecessor firms have been active in utility rate and economic consulting since 1937. The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some competitive retail power providers and utilities and, on occasion, state regulatory agencies. In addition, we have prepared depreciation and feasibility studies relating to utility service. We assist in the negotiation of contracts and the solicitation and procurement of competitive energy supplies for large energy users, provide economic policy analysis on industry restructuring issues, and present seminars on utility regulation. In general, we are engaged in regulatory consulting, economic analysis, energy procurement, and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas and Phoenix, Arizona.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN CONTESTED UTILITY PROCEEDINGS?

A. Yes, I have filed written testimony in the following dockets:

1. Texas Docket No. 10035 – Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Change Fixed Fuel Factors;

2. Texas Docket No. 10200 – Application of the Texas - New Mexico Power Company for Authority to Change Rates;

3. Texas Docket No. 10325 – Application of the Central Texas Electric Cooperative, Inc. for Authority to Change Rates;

4. Texas Docket No. 10600 – Application of the Brazos River Authority for Approval of Rates;

5. Texas Docket No. 10881 – Application of the New Era Electric Cooperative, Inc. for Authority to Change Rates;

6. Texas Docket No. 11244 – Petition of the Medina Electric Cooperative, Inc. to Reduce its Fixed Fuel Factor and the Application of the South Texas Electric Cooperative, Inc. for Authority to Refund an Over-Recovery of Fuel Cost Revenues and to Reduce its Fixed Fuel Factor;

7. Texas Docket No. 11271 – Application of Bowie-Cass Electric Cooperative, Inc. for Authority to Change Rates;

8. Texas Docket No. 11567 – Application of Kaufman County Electric Cooperative, Inc. for Authority to Change Rates;

9. Texas Docket No. 18607 – Application of West Texas Utilities Company for Authority to Reconcile Fuel Costs;

10. Texas Docket No. 20290 – Application of Central Power & Light Company for Authority to Reconcile Fuel Costs;

11. Virginia Case No. PUE980814 – In the matter of considering an electricity retail access pilot program: American Electric Power – Virginia;

12. Texas Docket No. 21111 – Application of Entergy Gulf States Inc. for Authority to Reconcile Fuel Costs and to Recover a Surcharge for Under-Recovered Fuel Costs;

13. Virginia Case No. PUE990717 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Virginia Code Section 56-249.6;

14. Texas Docket No. 22344 – Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule § 25.344;

15. Texas Docket No. 22350 – Application of TXU Electric Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Phase III);

16. Texas Docket No. 22352 – Application of Central Power and Light Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

17. Texas Docket No. 22353 – Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

18. Texas Docket No. 22354 – Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

19. Texas Docket No. 22356 – Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344;

20. Texas Docket No. 22349 – Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

21. Virginia Case No. PUE000584 – Application of Virginia Electric and Power Company for Approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act;

22. Texas Docket No. 24468 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southwest Power Pool;

23. Texas Docket No. 24469 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southeastern Electric Reliability Council;

24. Virginia Case No. PUE-2002-00377 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Section 56-249.6 of the Code of Virginia;

25. Texas Docket No. 27035 – Application of Central Power and Light Company for Authority to Reconcile Fuel Costs;

26. Texas Docket No. 28818 – Application of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area in Texas;

27. Virginia Case No. PUE-2000-00550 – Appalachian Power Company d/b/a American Electric Power: Regional Transmission Entities;

28. Texas Docket No. 29408 – Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs;

29. Texas Docket No. 29801 – Application of Southwestern Public Service Company for: (1) Reconciliation of its Fuel Costs for 2002 and 2003; (2) A Finding of Special Circumstances; and (3) Related Relief;

30. Texas Docket No. 30143 – Petition of El Paso Electric Company to Reconcile Fuel Costs;

31. Texas Docket No. 31540 – Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Substantive Rule 25.501;

32. Texas Docket No. 32795 – Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA Section 39.253(f);

33. Texas Docket No. 33309 – Application of AEP Texas Central Company for Authority to Change Rates;

34. Texas Docket No. 33310 – Application of AEP Texas North Company for Authority to Change Rates;

35. Michigan Case No. U-15245 – In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Rate Relief;

36. Texas Docket No. 34800 – Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs;

37. Texas Docket No. 35717 – Application of Oncor Electric Delivery Company LLC for Authority to Change Rates.

38. RIPUC Docket No. 4065 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-3-11;

39. RIPUC Docket No. 4323 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-1-3-11;

40. Oregon Docket No. UE 283 – In the Matter of Portland General Electric Company's Request for a General Rate Revision;

41. Washington Docket No. UE-141368 – In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes;

42. Federal Energy Regulatory Commission Docket No. EL15-82-000 – Illinois Industrial Energy Consumers, Complainant, v. Midcontinent Independent System Operator, Inc., Respondent;

43. RIPUC Docket No. 4568 – In Re: Review of the Narragansett Electric Company d/b/a National Grid's Rate Design Pursuant to R.I. General Laws Section 39-26.6-24;

44. Washington Docket Nos. UE-170033 and UG-170034 – Washington Utilities and Transportation Commission, Complainant, v. Puget Sound Energy, Respondent;

45. RIPUC Docket No. 4770 – The Narragansett Electric Company d/b/a National Grid – Application for Approval of a Change in Electric and Gas Base Distribution Rates;

46. RIPUC Docket No. 4780 – The Narragansett Electric Company d/b/a National Grid – Proposed Power Sector Transformation Vision and Implementation Plan;

47. Federal Energy Regulatory Commission Docket Nos. ER19-1486-000 and ER19-58-000, Enhanced Price Formation In Reserve Markets of PJM Interconnection, L.L.C.; and

48. Texas Docket No. 49494 – Application of AEP Texas Inc. for Authority to Change Rates.

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-190529 and UG-190530 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferral Accounting and Ratemaking Treatment For Short-life UT/Technology Investment	DOCKETS UE-190274 and UG-190275 (*consolidated*)

EXHIBIT AZA-3

COST OF SERVICE STUDY RESULTS – PARITY RATIOS

NOVEMBER 22, 2019

Puget Sound Energy

Cost of Service Study Results
Parity Ratios

Line	Customer Class	Company Peak Credit[1]	FEA Proposed Average & Excess 4 NCP	FEA Proposed 100% 4 CP
		(1)	(2)	(3)
1	Residential (Sch7)	0.97	0.95	0.94
2	Sec Volt (Sch 24, kW<50)	1.05	1.07	1.05
3	Sec Volt (Sch 25, kW>50&<350)	1.06	1.06	1.07
4	Sec Volt (Sch 26, kW>350)	1.06	1.11	1.15
5	Pri Volt (Sch 31)	1.02	1.06	1.10
6	Pri Volt (Sch 35)	0.55	0.45	0.75
7	Pri Service (Sch 43)	0.88	1.26	1.26
8	Special Contract	1.19	1.20	1.24
9	High Volt (Sch 46/49)	1.05	1.13	1.27
10	Choice / Retail Wheeling (Sch 448/449)	0.87	1.20	1.18
11	Lighting (Sch 50-59)	0.94	0.91	0.98
12	Firm Resale	0.50	0.50	0.49
13	Total	1.00	1.00	1.00

Source:
[1] Based on Company's Supplemental Filing per witness Birud D. Jhaveri.

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-190529 and UG-190530 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferral Accounting and Ratemaking Treatment For Short-life UT/Technology Investment	DOCKETS UE-190274 and UG-190275 (*consolidated*)

EXHIBIT AZA-4

**ELECTRIC CLASS COST OF SERVICE STUDY RESULTS
AT PRESENT AND COMPANY PROPOSED RATES UNDER
THE COMPANY'S COST OF SERVICE STUDY**

NOVEMBER 22, 2019

Puget Sound Energy

Electric Class Cost of Service Study Results at Present and Company Proposed Rates
Under the Company's Cost of Service Study
Adjusted Test Year Twelve Months ended December 2018 @ Proforma Rev Requirement

				Present Rates			Proposed Rates		
Line	Customer Class	Rate Base ($000)	Operating Income at Present Rates ($000)	Rate of Return	Relative Rate of Return	Over/(Under) Collection ($000)	Rate of Return	Relative Rate of Return	Over/(Under) Collection ($000)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential (Sch7)	$ 3,133,660	$ 157,951	5.04%	81	$ (49,717)	7.08%	86	$ (47,324)
2	Sec Volt (Sch 24, kW<50)	$ 652,114	$ 52,743	8.09%	130	$ 16,103	10.42%	127	$ 19,155
3	Sec Volt (Sch 25, kW>50&<350)	$ 675,201	$ 57,648	8.54%	137	$ 20,716	10.27%	125	$ 18,524
4	Sec Volt (Sch 26, kW>350)	$ 382,893	$ 32,201	8.41%	135	$ 11,095	10.22%	124	$ 10,242
5	Pri Volt (Sch 31)	$ 288,324	$ 20,204	7.01%	112	$ 2,973	9.27%	113	$ 4,077
6	Pri Volt (Sch 35)	$ 1,537	$ (119)	-7.74%	-124	$ (286)	-6.23%	-76	$ (295)
7	Pri Service (Sch 43)	$ 37,215	$ 916	2.46%	39	$ (1,868)	4.53%	55	$ (1,823)
8	Special Contract	$ 31,615	$ 3,165	10.01%	161	$ 1,590	7.46%	91	$ (317)
9	High Volt (Sch 46/49)	$ 98,737	$ 7,825	7.92%	127	$ 2,224	9.68%	118	$ 1,934
10	Choice / Retail Wheeling (Sch 448/449)	$ 67,834	$ 3,397	5.01%	80	$ (1,105)	5.09%	62	$ (2,815)
11	Lighting (Sch 50-59)	$ 57,658	$ 2,618	4.54%	73	$ (1,298)	6.60%	80	$ (1,237)
12	Firm Resale	$ 1,801	$ (209)	-11.61%	-186	$ (428)	3.20%	39	$ (120)
13	**Total**	**$ 5,428,588**	**$ 338,339**	**6.23%**	**100**	**$ 0**	**8.21%**	**100**	**$ (0)**

Source:
Based on Company's Supplemental Filing per witness Birud D. Jhaveri.

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-190529 and UG-190530 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferral Accounting and Ratemaking Treatment For Short-life UT/Technology Investment	DOCKETS UE-190274 and UG-190275 (*consolidated*)

EXHIBIT AZA-5

FEA'S PROPOSED ELECTRIC REVENUE DISTRIBUTION

NOVEMBER 22, 2019

Puget Sound Energy

FEA's Proposed Electric Revenue Distribution

Adjusted Test Year Twelve Months ended December 2018 @ Proforma Rev Requirement

Line	Customer Class	Present Revenues ($000)	Company Proposed Increase Amount ($000)	Company Proposed Increase Percent	FEA's Proposed Increase[1] Amount ($000)	FEA's Proposed Increase[1] Percent
		(1)	(2)	(3)	(4)	(5)
1	Residential (Sch7)	$ 1,105,897	$ 84,939	7.68%	$ 139,626	12.63%
2	Sec Volt (Sch 24, kW<50)	$ 263,390	$ 20,230	7.68%	$ -	0.00%
3	Sec Volt (Sch 25, kW>50&<350)	$ 270,703	$ 15,594	5.76%	$ -	0.00%
4	Sec Volt (Sch 26, kW>350)	$ 160,281	$ 9,233	5.76%	$ -	0.00%
5	Pri Volt (Sch 31)	$ 113,255	$ 8,699	7.68%	$ -	0.00%
6	Pri Volt (Sch 35)	$ 268	$ 31	11.52%	$ 45	16.64%
7	Pri Service (Sch 43)	$ 10,687	$ 1,026	9.60%	$ 1,564	14.63%
8	Special Contract	$ 5,494	$ (1,075)	-19.56%	$ (1,075)	-19.56%
9	High Volt (Sch 46/49)	$ 40,128	$ 2,312	5.76%	$ -	0.00%
10	Choice / Retail Wheeling (Sch 448/449)	$ 10,117	$ 77	0.76%	$ 77	0.76%
11	Lighting (Sch 50-59)	$ 16,457	$ 1,580	9.60%	$ 2,408	14.63%
12	Firm Resale	$ 324	$ 355	109.43%	$ 355	109.43%
13	**Total**	**$ 1,997,002**	**$ 143,000**	**7.16%**	**$ 143,000**	**7.16%**

Note:
[1] Assumes no increase to the Secondary, Primary (Sch 31) and High Voltage classes.