BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

(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

DOCKETS UE-220066 and
UG-220067

DOCKET UG-210918

RESPONSE TESTIMONY AND EXHIBITS OF ALI AL-JABIR

ON BEHALF OF

THE FEDERAL EXECUTIVE AGENCIES

July 28, 2022
TABLE OF CONTENTS

Rates Should Be Established Based On Class Cost of Service .................................................. 5
Classification and Allocation of Generation Fixed Costs .......................................................... 11
Classification and Allocation of Wheeling Expenses ............................................................... 16
Allocation of Distribution Poles and Wires Costs ................................................................. 17
Electric Revenue Allocation ...................................................................................................... 21
Rate Design of the Colstrip and Multi-Year Rate Plan Riders .................................................. 25

Exhibit No. AZA-2: Qualifications of Ali Al-Jabir

Exhibit No. AZA-3: Cost of Service Study Results – Parity Ratios

Exhibit No. AZA-4: Electric Class Cost of Service Study Results at Present and
Company Proposed Rates Under the Company’s Cost of Service Study

Exhibit No. AZA-5: Comparison of PSE’s and FEA’s Proposed Electric Revenue Distribution
– Base Rate Revenue

Exhibit No. AZA-6: Comparison of PSE’s and FEA's Proposed Electric Revenue Distribution
– Total Rate Revenue
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 non-
coincident 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.
Rates Should Be Established Based On Class Cost of Service

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 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 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
Commission’s cost of service methodology rule. Therefore, it is my understanding that

\(^1\) WAC 480-85-060(2).
\(^2\) WAC 480-85-070.
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 CCCSS 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.

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

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

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.

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

\[2\] Prefiled Direct Testimony of Birud D. Jhaveri (Exhibit BDJ-1T) at p. 19.

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

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9/ Prefiled Direct Testimony of Binud D. Jhaveri (Exhibit BDJ-1T) at p. 22.
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 CCOS 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. 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

\(^{2}\) 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.

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 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 parity8/.

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

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

**Rate Design of the Colstrip and Multi-Year Rate Plan Riders**

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.\(^{9/}\) 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 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

\(^{9/}\) PSE’s response to FEA data request no. 17.
\(^{10/}\) PSE’s response to FEA data request no. 18.
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.