BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

V.

PUGET SOUND ENERGY,

Respondent.

DOCKETS UE-170033 & UG-170034 (*Consolidated*)

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1T)

ON BEHALF OF

WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL,

PUBLIC COUNSEL UNIT

JUNE 30, 2017

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DOCKETS UE-170033 and UG-170034 (*Consolidated)*

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EXHIBITS LIST

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia 23229.

Q: What is your professional and educational background?

A: I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. Except for a six- month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 36-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada. I have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. This experience includes serving as a witness for the Public Counsel Unit of the Washington State Office of the Attorney General ("Public Counsel") in several proceedings before this Commission. In addition, I have provided expert testimony before state and federal courts as well as before state legislatures. I provide a more complete description of my education and experience in Exhibit No. GAW-2.

Q: What is the purpose of your testimony in this proceeding?

A: Public Counsel retained Technical Associates to evaluate the accuracy and reasonableness of Puget Sound Energy's ("PSE" or "Company") electric and natural gas class cost of service studies ("CCOSS"), proposed distribution of revenues by class, and residential rate designs. The purpose of my testimony, therefore, is to comment on PSE's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of Public Counsel.

Q: Please explain how your direct testimony is structured.

A: In addition to this introduction, I have separated my direct testimony into two sections: Electric Operations and Natural Gas Operations. For each operational section, I have three subsections entitled: Class Cost of Service, Class Revenue Distribution, and Residential Rate Design. My analyses and testimony are based on the Company's supplemental filing and direct testimony dated April 3, 2017.

II. ELECTRIC OPERATIONS

A. Electric Cost of Service

Q: Please briefly explain the concept of a class cost of service study ("CCOSS") and its purpose in a rate proceeding.

A: Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the Washington Utilities and Transportation Commission ("WUTC"), PSE has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expenses are incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although cost analysts strive to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors and must be subjectively assigned or allocated to customer rate classes. With regard to those costs which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor (e.g., peak demand, energy usage, number of customers, etc.).

Q: In your opinion, how should the results of a CCOSS be utilized in the ratemaking process?

A: Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise due to the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In this regard, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to certain costs.

Q: Have the higher courts opined on the usefulness of cost allocations for purposes of establishing revenue responsibility and rates?

A: Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (the predecessor to FERC), the United States Supreme Court stated, "But whereas here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[1]

Q: Does your opinion, and the findings of the U.S. Supreme Court, imply that cost allocations should play no role in the ratemaking process?

A: Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or

[1] *Colorado Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, 65 S. Ct. 829, 89 L. Ed. 1206 (1945).

greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q: Before you discuss specific cost allocation methodologies, please explain how generation/production-related costs are incurred. In doing so, please explain the cost causation concepts relating to generation/production resources.

A: Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which facilities are serving which customers. As such, production facilities are joint costs, i.e., they are used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour (“kWh”) would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that PSE experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, not all customer classes contribute in equal proportions to these varying demands placed on the generation system. Further complicating matters, the electric utility industry is unique in that there is a distinct energy/capacity trade-off relating to production costs. That is, utilities generally design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands.[2] The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investments per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy (i.e., its cost of service).

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q: Please explain.

A: Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes every hour of the year. This would result in 8,760 hourly allocations. Although such an analysis is certainly possible with today's technology, hourly supply (generation) and demand (customer load) data is required to conduct such hour-by-hour analyses. While most utilities can and do record hourly production output, they often do not estimate class loads on an hourly basis (at least not for every hour of the year). With these constraints in mind, several allocation

[2] In recent years, many utilities are required to also incorporate generation facilities that reduce carbon emissions and/or utilize renewable resources in their generation portfolios that may not be the most efficient from a cost minimization perspective.

methodologies have been developed to allocate electric utility generation plant investment and attendant costs. Each of these methods has strengths and weaknesses regarding the reasonableness in reflecting cost causation.

Q: Approximately how many cost allocation methodologies exist relating to the allocation of generation plant?

A: The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual[3] discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[4]

Q: Briefly discuss the strengths and weaknesses of common generation cost allocation methodologies.

A: A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

Single Coincident Peak: The basic concept underlying the Single Coincident Peak method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the Single Coincident Peak method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the Single Coincident Peak method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are less significant than some more complex methods.

[3] Staff Subcommittees on Electricity and Economics, Nat'l Ass'n of Regulatory Util. Comm'nrs, Electric Utility Cost Allocation Manual (1992).

[4] James C. BonBright et al., Principles of Public Utility Rates, at 495 (2d ed. 1988).

The Single Coincident Peak method has several shortcomings, however. First, and foremost, is the fact that the Single Coincident Peak method ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning 100 percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as PSE had a peak load of 4,000 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle, and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 4,000 mW for one hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the Single Coincident Peak method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The “free ride” problem is another major shortcoming of the Single Coincident Peak method. A summer-peaking utility that peaks at about 5:00 p.m. clearly illustrates this problem.

Because street lights are not on at this time of day during summer months, this class will not be assigned any capacity costs and will, therefore, enjoy a “free ride” on the assignment of generation costs that this class requires.

Four Coincident Peak Method: The Four Coincident Peak method is identical in concept to the Single Coincident Peak method except that the analysis relies on the peak loads during the highest four months. This method generally exhibits the same advantages and disadvantages as the Single Coincident Peak method. As a result, it is no more reasonable to use the Four Coincident Peak method versus the Single Coincident Peak method.

Summer and Winter Coincident Peak Method: The Summer and Winter Coincident Peak method was developed because some utilities’ annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the Summer and Winter Coincident Peak attempts to recognize this. This method is essentially the same as the Single Coincident Peak method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the Single Coincident Peak method, and in my opinion, is no more reasonable than the Single Coincident Peak method.

Twelve Coincident Peak Method: Arithmetically, the Twelve Coincident Peak method is essentially the same as the Single Coincident Peak method except that class contributions to each monthly peak are considered. Although the Twelve Coincident Peak method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities than does the Single Coincident Peak or Four Coincident Peak methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the Twelve Coincident Peak method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system is in place to record class-by-class load data, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average: The various Peak and Average methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the Peak and Average method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how to measure peak demands or how the weighting between peak and average demands should be performed, most electric Peak and Average studies use class contributions to coincident-peak demand for the "peak" portion and weight the peak and average loads based on the system coincident load factor. Put differently, the system load factor often represents the portion assigned based on consumption (average demand).

The major strengths of the Peak and Average method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the Peak and Average method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the Peak and Average method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class consumes a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the Peak and Average method can produce fair and reasonable results.

Average and Excess: The Average and Excess method also considers both peak demands and energy consumption throughout the year. However, the Average and Excess method is much different than the Peak and Average method in both concept and application. The Average and Excess method recognizes class load diversity within a system, such that not all classes call on the utility's resources to the same degree, at the same times. Mechanically, the Average and Excess method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the result will be the same as that achieved under the Single Coincident Peak method.

Although the Average and Excess method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the Average and Excess method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the Average and Excess method is that extensive and accurate class load data is required.

<u>Base-Intermediate-Peak</u>: The Base-Intermediate-Peak method, also known as a production stacking method, explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general and specifically recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The Base-Intermediate-Peak method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the Base-Intermediate-Peak method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units with high capacity factors run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource, i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year.

Intermediate resources are classified and allocated based on their relative usage to peak capability ratios, i.e., their capacity factor.

Finally, hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis in order to minimize short-term energy costs and assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the Base-Intermediate-Peak method is the same as under other methods where no recognition is given to potentially lower variable fuel costs during off-peak periods.

Probability of Dispatch: The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year. Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units, which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only a few peak hours of the year. The hourly capacity costs for each generating asset are summed to develop hourly investments. These hourly investments are then assigned to individual rate classes based on hourly class contributions to system load. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed class load studies encompassing each hour of the year (8,760 hours).

Peak Credit (also known as Equivalent Peaker): The Peak Credit method is more commonly known as the Equivalent Peaker approach. This method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The Peak Credit method relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

This method has substantial intuitive appeal in that it attempts to capture a surrogate for the marginal cost of electricity production. However, the major shortcomings of this method are that a hypothetical peaker unit must first be selected with assumed levels of investment costs, operating and fuel costs, levels of dispatch throughout a year, forecasts of future fuel and operating costs, and assumed levels of capital costs and inflation rates. As a result, the assumptions and inputs are not known with certainty and are often the source of considerable controversy.

Q: Mr. Watkins, you have discussed the strengths and weaknesses of the more common generation allocation methodologies. Are any of these methods clearly inferior in your view?

A: Yes. In my opinion the Single Coincident Peak and seasonal Coincident Peak (such as Four Coincident Peak) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality, but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The Single Coincident Peak and seasonal Coincident Peak methods totally ignore this very important fact.

Q: What cost allocation methodology did Mr. Piliaris utilize to allocate generation plant costs within his CCOSS?

A: Mr. Piliaris utilized the long-standing approved Peak Credit method to allocate PSE's generation assets.

Q: Did the WUTC's direction and orders guide your analysis and presumably that of Mr. Piliaris?

A: Yes. Since at least the early 1990s, the accepted electric cost allocation method to assign generation and transmission-related costs in Washington has been the Peak Credit method, which is also known as the Equivalent Peaker method. In its Final Order approving and adopting a settlement agreement in PSE's Cost of Service Collaborative, Docket No. UE-141368 (Order 03, dated January 29, 2015), the Commission directed the parties to rely upon the Peak Credit methodology in PSE's next rate case (the pending case) and to classify generation and transmission plant as 75 percent energy-related and 25 percent demand-related. In this regard, I have evaluated Company witness Piliaris' testimony and exhibits that comport with this requirement.

In addition, and because there is no absolutely correct or precise cost allocation method or approach, I have also conducted additional studies based on alternative allocation methodologies that reasonably reflect cost causation and are fair and reasonable to all rate classes. Moreover, my studies based upon alternative methodologies serve as a check on the reasonableness of the Peak Credit methodology.

Q: Please explain how you proceeded with your analysis of PSE's CCOSS.

A: In conducting my independent analysis, I reviewed the structure and organization of the Company's CCOSS and examined the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed PSE's selection of allocators to specific rate base, revenue, and expense accounts. I then verified the accuracy of PSE's CCOSS model by replicating its results using my own computer model. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

Q: With regard to Mr. Piliaris' supplemental CCOSS utilizing the peak credit method, do you have disagreements with Mr. Piliaris' allocation of individual rate base or operating income accounts?

A: Yes, albeit minor. Before I discuss my specific disagreements, recall that many joint or common costs cannot be ascribed to a specific cost causation factor. This is particularly true for the Company's overhead costs, including general plant and administrative and general expenses. For example, Mr. Piliaris has allocated the majority of general plant based on previously allocated salaries and wages expenses. While this approach cannot be considered unreasonable, many (if not most) CCOSSs conducted by experts allocate general plant based on previously allocated total production, transmission, and distribution plant. Similarly, Mr. Piliaris allocated working capital based on total plant in service, whereas it is perhaps more common to assign working capital costs across classes based on O&M expenses. While I acknowledge there is no absolutely correct or incorrect method to assign overhead costs, I conducted sensitivity analyses utilizing alternative allocators for various overhead and plant costs and have found no material difference in the overall results. As such, I accept Mr. Piliaris' selection of allocators by account with the exception of those discussed below.

However, I observed what appears to be one small mathematical error in Mr. Piliaris' CCOSS, and I disagree with the proper allocation of a few expense accounts. The minor mathematical error relates to Mr. Piliaris' allocation of certain "other rate base" accounts functionalized as transmission-related. Specifically, this error relates to the following: (1) Intangible Transmission Plant; (2) Miscellaneous Deferred Debits – Transmission; (3) Accumulated Deferred Income Taxes – Transmission; (4) Customer

Deposits – Transmission; (5) Acquisition Adjustment – Transmission; (6) Amortization of the Acquisition Adjustment – Transmission; and, (7) Asset Retirement Obligations – Transmission. In conducting his CCOSS, Mr. Piliaris allocated these items based on his classification and allocation of generation plant. Because the Retail Wheeling classes (Schedule 448 and 449) do not rely upon the Company's generation facilities, but utilize the majority of the Company's transmission resources, Mr. Piliaris erred by not assigning any of the above-referenced transmission costs to the Retail Wheeling class. I have corrected this apparent error using the same concept and method as Mr. Piliaris, but have included the assignment of a portion of these costs to the Retail Wheeling class.

My disagreement with Mr. Piliaris' selection of allocators relates to the assignment (or calculation) of income taxes, fuel costs, state excise taxes, and WUTC fees. With regard to Federal income taxes, Mr. Piliaris allocated income taxes at current rates based on each class' total rate base. This calculation does not reflect an accurate portrayal of each class' contribution to profitability at current rates since income taxes are a function of current revenues minus expenses, rather than allocated rate base.[5] In conducting my analyses at current rates, I have calculated each class' income tax responsibility based on current revenues minus current expenses minus interest expense, which provides a more accurate portrayal of income tax responsibility. This can readily be understood by evaluating two hypothetical classes. One in which the calculated operating income before income taxes is exceptionally high (resulting in a high before-tax ROR) and, another in which the operating income before income taxes is

[5] However, in determining individual class revenue requirements, it is acceptable to allocate income taxes to classes based on rate base since the required operating income is a direct function of allocated rate base.

exceptionally low (resulting in a low before-tax ROR). If one were to assume each class had the same level of rate base, Mr. Piliaris would assign the same level of income tax responsibility to each class even though the low ROR class may actually have negative taxable income at current rates. In large part, my disagreement with Mr. Piliaris' assignment of income tax responsibility is immaterial in that this Commission historically has relied upon parity ratios in evaluating class profitability and revenue responsibility.[6] That is, while my determination of income tax responsibility at current rates is significantly different from the income taxes allocated by Mr. Piliaris at current rates, the required income taxes (at the Company's requested revenue requirement) are very similar across classes. As a result, there is little difference in the parity ratios as a result of our disagreement in the determination of income tax responsibility.

With regard to the allocation of fuel costs, Mr. Piliaris classified and allocated these costs as 25 percent demand-related and 75 percent energy-related. It is well known and universally accepted that generation fuel costs are variable in nature and are 100 percent energy-related, as these costs vary directly with the energy produced throughout the year. In this regard, I classified and allocated fuel costs based totally on annual KWH (at generation). It should be noted that there is theoretically a more accurate method to assign fuel costs based on when each class relies upon a utility's generation resources. This more theoretical approach is known as time differentiated fuel costs. To illustrate, the reasons why one class of customers may impose different fuel costs than another class, consider a class that utilizes electricity largely or totally during off-peak periods (i.e., street lighting at night). During off-peak periods, utilities typically run base load

[6] Parity ratio is the ratio of each class' relative current revenue to the allocated revenue requirement.

units with variably low fuel costs such that high fuel cost plants, such as peakers, are not dispatched during the time periods when these off-peak customers use electricity. On the other hand, consider a class that uses electricity largely during peak demand periods, such as a supplemental heating customer class in which fuel costs tend to be higher during these on-peak periods.

As I will discuss later in my testimony, I have also conducted a time differentiated fuel cost analysis and found little difference in fuel cost per kWh across PSE's rate classes. Therefore, I conclude that an allocation of annual fuel costs based on annual kWh (consumption), adjusted for line losses, is reasonable for PSE.

My final disagreements with Mr. Piliaris' selection of allocators for specific accounts relate to state excise taxes (Account 236.02) and WUTC fees (Account 928). These two cost items are a direct function of revenues. However, Mr. Piliaris allocated state excise taxes at current rates based upon a close approximation of each class' revenue requirement.[7] As is the case with Mr. Piliaris' calculation of income taxes at current rates, my disagreement is not material so long as the Commission relies upon class parity ratios instead of class RORs at current rates since the calculated State Excise taxes at the Company's requested ROR is about the same under both approaches.

With regard to WUTC fees, it is my understanding that the Commission assesses these fees based on revenues. However, Mr. Piliaris allocated this expense account based on total production, transmission, and distribution expenses. It is more appropriate to base the allocation factor on rate revenues.

[7] Specifically, Mr. Piliaris allocated State Excise taxes at current rates based upon total O&M expense plus depreciation expense plus required return on rate base at the Company's proposed level.

Q: Do your corrections and minor disagreements with Mr. Piliaris' Peak Credit study result in any material change to class parity ratios?

A: No. Table 1 below provides a comparison of class parity ratios under Mr. Piliaris' supplemental CCOSS as well as that modified for the changes discussed above:

Table 1
Peak Credit CCOSS Comparison
Utilizing 75% Energy/25% Demand
Parity Ratios

Rate Schedule	Class	Piliaris' Supplemental	PC Corrected
7	Residential	95%	96%
24	Secondary Voltage <50kw	109%	108%
25/29	Secondary Voltage >50kw and <350kw	108%	107%
26	Secondary Voltage >350	107%	106%
31	Primary Voltage	106%	105%
35	Irrigation	62%	61%
43	All Electric Schools	100%	98%
40	Campus	100%	99%
46/49	High Voltage	109%	107%
449/459	Choice/Retail Wheeling	64%	65%
50/59	Lighting	96%	96%
5	Firm Resale	47%	48%
Total Company		100%	100%

Q: Have you also conducted CCOSS analyses utilizing the Peak Credit methodology using an alternative energy/demand split to the 75 percent energy/25 percent demand ordered by the Commission in Docket No. UE-141368?

A: Yes. As noted by Mr. Piliaris in his direct testimony, the Company updated its Peak Credit analyses using current information, which results in a classification of generation and transmission plant as 82 percent energy and 18 percent demand. Utilizing this classification for generation and bulk transmission-related costs, I calculated the following parity ratios (including my minor corrections and disagreements to Mr. Piliaris):

Table 2
Peak Credit CCOSS Comparison
Utilizing 82% Energy/18% Demand
Parity Ratios

Rate Schedule	Class	Piliaris' Supplemental
7	Residential	96%
24	Secondary Voltage <50kw	108%
25/29	Secondary Voltage >50kw and <350kw	106%
26	Secondary Voltage >350	105%
31	Primary Voltage	104%
35	Irrigation	59%
43	All Electric Schools	93%
40	Campus	98%
46/49	High Voltage	105%
449/459	Choice/Retail Wheeling	63%
50/59	Lighting	96%
5	Firm Resale	49%
Total Company		100%

Although there are minor differences in the absolute parity ratios from those developed using a 75 percent energy/25 percent demand classification, the differences are minimal.

Q: Have you conducted alternative studies that may more accurately represent the capacity and energy trade-offs exhibited in PSE's actual generation plant investment?

A: Yes. There is no single, or absolute, correct method to allocate joint generation costs. While some methods are superior to others, it is my opinion that the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

In my opinion, the Probability of Dispatch and Base-Intermediate-Peak methods more accurately reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. This is particularly true and important for PSE given the large amount of investment in generation provided from hydroelectric and wind facilities, as well as its investment and generation provided from the Colstrip generating units.

The importance of considering PSE's wind and hydro generation is that these types of generation are not always available to meet system load due to various constraints. For example, wind generation is only available when weather conditions allow. Similarly, and as discussed earlier, hydro generation is often subject to several environmental constraints including water levels, river flow, fish and wildlife regulations, etc.

Indeed, I evaluated the amount of PSE's wind generation available at various peak periods. PSE is invariably a winter peaking utility. In response to Public Counsel Data Request No. 300 and Public Counsel Data Request No. 301,[8] the Company provided hourly system demands and hourly generation by unit for multiple years. During the last two years, wind generation accounted for virtually no production during any of the highest annual 25 hours of system peak demand. At the same time, the Company's hydro facilities only operated at about 48 percent of capacity during these 50 hours of peak demand (highest 25 hours for each of the last two years). Exhibit No. GAW-5 contains details supporting these observations. Therefore, while the Company's wind and hydro units produced a considerable amount of energy throughout the year, these facilities

[8] Provided as Exh. GAW-3 and Exh. GAW-4. Due to the voluminous nature of these Exhibits, they are provided in electronic format only.

cannot be fully relied upon to meet system load in any given hour. Conversely, PSE's ownership in the Colstrip generating units provides customers with relatively inexpensive variable fuel costs such that these units are considered base load facilities. Finally, PSE owns and operates numerous gas and oil fired generating facilities including combined cycle and combustion turbine units – some of which operate on an intermediate basis, while others are generally dispatched for a few hours of the year during peak demand periods. Taking all of this into consideration, I conducted alternative CCOSS that recognize the actual configuration, dispatch, utilization, and investment of PSE's generating resources utilizing the Base-Intermediate-Peak and Probability of Dispatch methods.

1. Base-Intermediate-Peak Method

Q: Please explain how you conducted your CCOSS utilizing the Base-Intermediate-Peak method.

A: In order to reflect the capacity/energy trade-off inherent in PSE's mix of generating resources, each plant's maximum capacity (mW) and output (mWh) during the test year is required. Exhibit No. GAW-6 provides the classification between energy and demand for PSE's generation plant under the Base-Intermediate-Peak method. The Base-Intermediate-Peak method evaluates each plant based on its capacity factor and variable fuel costs to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements. To illustrate, the Colstrip units are base load units in that they exhibit low running (fuel) costs per kWh. Several of the Company's gas fired combined cycle units are intermediately dispatched during periods of moderate to high peak demand since these facilities exhibit relatively low variable running costs, albeit higher than that for the Colstrip units. As shown in Exhibit No. GAW-6, the Company has four generating facilities that can be considered peaker units in that they operate with high variable running costs and are only dispatched a few hours of the year in order to meet peak load requirements. As discussed earlier, PSE has installed a considerable amount of hydro and wind generation capacity.

As indicated in Exhibit No. GAW-6, the Company's base load units are classified as 100 percent energy-related. Intermediate units are classified between energy and demand depending upon each unit's actual capacity factor during the test year. Peaker units have been classified as 100 percent demand-related. In addition to those generating units, hydro and wind units have been classified as 52 percent energy/48 percent demand and 94 percent energy/six percent demand, respectively. Exhibit No.GAW-5 supports this classification. When considering and weighting each unit based on its net investment, the result is a generation classification of 74.47 percent energy and 25.53 percent demand. I have rounded these numbers to 75 percent energy and 25percent demand, which matches exactly with the classification used by Mr. Piliaris under his Peak Credit methodology.

With this analysis in mind, the class rates of return and parity ratios under the Base-Intermediate-Peak method are the same as those under the Peak Credit method using 75 percent energy/25 percent demand split. As a result, while the Peak Credit methodology uses an entirely different approach than the Base-Intermediate-Peak method, both methods produce the same results for PSE. As a result, and for purposes of this case, the Peak Credit method is considered a reasonable approach to allocate production-related costs.

2. Probability of Dispatch Method

Q: Please explain how you conducted your CCOSS utilizing the Probability of Dispatch method.

A: As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, PSE provided both of these critical data sets. As such, I was able to conduct CCOSS utilizing the Probability of Dispatch method. In this regard, the Company provided hourly class loads and generation output by individual unit in response to Public Counsel Data Request Nos. 300 and 301 for three separate 12-month periods.[9] In consulting with PSE personnel regarding the availability of the data required to conduct the Probability of Dispatch method, it was apparent that the test year (September 30, 2016) was abnormally mild such that actual class loads and generation output for this period may not reasonably depict expected loads and dispatch of generating units. Therefore, in conducting my analyses, I conducted my studies utilizing both the test year experience of class loads and generation output by unit, in addition to the three-year average hourly contributions to system load coupled with the three-year average hourly generation output.

[9] The three 12-month periods provided are the test periods ending 9/30/16, 12/30/15, and 12/31/12 shown in Exh. GAW-3 and Exh. GAW-4.

The first step in conducting the Probability of Dispatch method is to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the <u>NARUC: Electric Utility Cost Allocation Manual</u>,[10] each plant's total gross investment and accumulated depreciation was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour. My Exhibit No. GAW-7 provides two pages of these hourly assignments. It should be noted that this exercise actually assigns costs to every hour of the year; however, my Exhibit No. GAW-7 only encompasses several of the first hours in the test year to avoid an Exhibit exceeding 250 pages. My filed workpapers contain the details of this assignment for every hour of the test year, as well as the other two annual periods analyzed. Page one of Exhibit No. GAW-7 provides the assignment of gross plant, while page two of this Exhibit details the assignment of each plant's depreciation reserve. This separate assignment between gross investment and depreciation reserve was performed due to the possibility of differences in the net book value of PSE's various generation facilities (i.e., some units may be more fully depreciated than others).

Once I determined hourly investment costs, I was able to assign these costs to individual rate classes on an hour-by-hour basis. As indicated earlier, PSE provided individual class loads for each hour of the test year as well as two prior annual periods. As such, I multiplied each class' relative contribution to the total system generation load in a given hour by the hourly generation investment cost. In order to develop class responsibility for PSE's net generation plant, I then summed hourly class investment

[10] Staff Subcommittees on Electricity and Economics, Nat'l Ass'n of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual at 62 (1992).

costs for all hours of the year. Exhibit No. GAW-8 provides summaries of the hourly assignment of generation costs to individual rate classes. I provide the class assignment to every hour of the test year and the two prior annual in my filed workpapers.

Q: Earlier in your testimony, you indicated that the Probability of Dispatch and Base-Intermediate-Peak methods might not properly recognize class variances in variable generation costs. Have you examined whether there are material differences in class fuel costs when analyzed on an hourly (time differentiated) basis?

A: Yes, I have. As discussed earlier, PSE provided each generation plant's hourly output over three annual periods. In addition, in response to Public Counsel Data Request No. 308, the Company provided annual average fuel costs (per kWh) for each plant for a three-year period. With this data, I was able to calculate hourly fuel costs by individual generating plant based on each unit's output. I then assigned these hourly fuel costs to individual rate classes on an hour-by-hour basis based on the class hourly loads previously discussed.[11] The result of this analysis yielded very similar hourly fuel costs for most classes. In this regard, the time differentiated fuel costs reflect all sources of generation, including wind and hydro with zero fuel costs. As a result, PSE's total fuel costs divided by total kWh is very low by industry standards (slightly more than $0.01/kWh). I provide each class' time differentiated fuel cost in Table 3 below. [12]

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[11] The class hourly loads were provided at the generation level. Each class' loads were adjusted for losses to reflect class loads at the meter as provided in response to Public Counsel Data Request No. 302.

[12] The details of this analysis are provided in my filed workpapers.

Table 3
PSE Class Hourly Fuel Costs

		Test Year		3-Year Average	
Class		Fuel Cost Per mWh	Deviation From Sys. Average	Fuel Cost Per mWh	Deviation From Sys. Average
Jurisdictional:					
7	Residential	$11.24	-1%	$11.77	-1%
24	Secondary <50kw	$11.43	1%	$12.11	2%
25/29	Secondary >50kw and <350kw	$11.53	2%	$12.20	3%
26	Secondary >350	$11.59	3%	$12.25	3%
31	Primary	$11.02	-2%	$11.69	-2%
35	Irrigation	$12.13	7%	$13.95	17%
43	All Electric Schools	$10.53	-7%	$10.95	-8%
40	Campus	$11.04	-2%	$11.69	-2%
46/49	High Voltage	$10.81	-4%	$11.50	-3%
449/459	Retail Wheeling	--	--	--	--
50/59	Lighting	$11.80	4%	$12.43	4%
Non-Jurisdictional:					
5	Firm Resale	$10.22	-10%	$10.58	-11%
Total		$11.30	--	$11.90	--

In examining these time differentiated fuel costs by class, there would appear to be a few anomalous results that with further investigation can be explained and understood. For example, even though the Lighting class is generally considered off-peak, this class' time differentiated fuel cost is higher than the system average. PSE's wind generation is small to non-existent during many evening hours. With regard to the Irrigation class, these customers utilized the preponderance of their annual electricity during the warm summer months. Even though PSE is a winter peaking utility, Irrigation customers tend to utilize electricity on warmer summer days (with reasonably high system loads) and during periods in which less hydro generation is available, thereby, increasing their average fuel cost per mWh. Finally, Rate Schedule 43 fuel costs are seven percent to eight percent below the system average fuel cost, but this is technically an Interruptible rate schedule.

Q: Have you incorporated time differentiated fuel costs within your Probability of Dispatch CCOSS?

A: Yes. My CCOSS utilizing the Probability of Dispatch method incorporates the time differentiated fuel costs previously discussed.

Q: Up to this point, you have explained how you have allocated generation-related costs under the Probability of Dispatch method. Please explain how you classified and allocated transmission-related costs under the Probability of Dispatch method.

A: Since at least the early-1990s, this Commission has consistently found that transmission facilities are an extension of generation facilities in that generation facilities are often located at a long distance from customers' load centers and that transmission is simply a conduit to transmit this distant generation to retail load centers. The Commission has consistently ruled that transmission facilities should be classified as partially energy-related and partially demand-related. Traditionally, electric utilities in the State have utilized the same demand/energy classification for transmission plant as they do for generation plant. Indeed, under Mr. Piliaris' Peak Credit method, he has classified transmission plant as 75 percent energy-related and 25 percent demand-related.[13] However, under the Probability of Dispatch method, there is no distinct energy and demand separation, or classification, per se. In order to separate my Probability of Dispatch approach from the Peak Credit approach entirely, I first split costs between classes that utilize PSE's generation resources and those transportation customers that wheel power. I conducted this separation by classifying common bulk transmission costs based on the system load factor of 66.5 percent energy/33.4 percent demand. After allocating bulk transmission costs to the Retail Wheeling class, I allocated the remaining costs to the generation classes based on the Probability of Dispatch generation allocator.

[13] There is a small amount of transmission plant directly-assigned to the Retail Wheeling class.

Q: Please provide a summary of the results obtained utilizing the Probability of Dispatch method.

A: The following table provides a comparison of the parity ratios obtained under the Probability of Dispatch methods to those calculated under the Peak Credit and Base-Intermediate-Peak methods utilizing 75 percent energy/25 percent demand (test year and three-year average):

Table 4
Comparison of Peak Credit and Base-Intermediate-Peak Results
75% Energy/25% Demand
to Probability of Dispatch Results
Parity Ratios

Rate Schedule	Class	Peak Credit And BIP	Prob. Of Dispatch: Test Year Experience	Prob. Of Dispatch: 3-Year Avg. Experience
7	Residential	96%	99%	99%
24	Secondary <50kw	108%	106%	107%
25/29	Secondary >50kw and <350kw	107%	103%	103%
26	Secondary >350	106%	99%	99%
31	Primary	105%	100%	99%
35	Irrigation	61%	50%	48%
43	All Electric Schools	98%	91%	90%
40	Campus	99%	92%	90%
46/49	High Voltage	107%	95%	94%
449/459	Choice/Retail Wheeling	65%	67%	67%
50/59	Lighting	96%	93%	92%
5	Firm Resale	48%	50%	50%
Total		100%	100%	100%

While there are some differences in the parity ratios between the various studies observable in the table above, the directional relationship of these parity ratios remains the same. More specifically, all studies indicate that the Irrigation (Rate 35), Retail Wheeling (Rate 449/459), and Firm Resale (Rate 5) class' parity ratios are significantly below 100 percent. This indicates that rates should increase by a higher percentage for these classes than the other classes. Equally important is the fact that all studies indicate that the remaining classes all exhibit parity ratios reasonably close (within +/- 10 percent) to 100 percent. Based on my experience in Washington, the Commission considers parity ratios within +/- 10 percent of unity equivalent to 100 percent parity. As such, these CCOSS findings indicate that all classes, except those with exceptionally low parity ratios, should incur uniform rate increases. My Probability of Dispatch CCOSS results in Exhibit No. GAW-9.

Q: Please provide a summary of your findings and conclusions relating to CCOSS for this case.

A: My Exhibit No. GAW-10 provides a comparison of parity ratios obtained from every CCOSS I evaluated for this proceeding. As indicated, the parity ratios are very consistent across all methods and approaches. That is, all studies indicate that the same classes consistently exhibit considerably low parity ratios, while these studies also indicate that all other classes' exhibit parity ratios reasonably close to unity (100 percent). Therefore, although the Peak Credit, Base-Intermediate-Peak, and Probability of Dispatch methods are all vastly different in concept, it is apparent that the results obtained by Mr. Piliaris' Peak Credit study are within the range of reasonableness. In this regard, while it is my opinion that the Probability of Dispatch approach is the most theoretically correct approach followed by the Base-Intermediate-Peak method, from a practical standpoint, the long accepted Peak Credit method produces reasonable results that are consistent with cost causation and are fair and equitable to all rate classes.

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B. Electric Class Revenue Distribution (Rate Spread)

Q: What general criteria did you consider in order to establish class revenue responsibility for electric utility rates?

A: There are several criteria that should be considered in evaluating class or rate revenue responsibility. First, class cost allocation results should be considered, but as discussed in detail earlier in my testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include:

- Gradualism, wherein rates should not drastically change instantaneously.
- Rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure.
- Affordability of electricity across various classes and a relative comparison of electricity prices across classes.
- Public policy concerning current economic conditions and economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria to be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. As such, there is no universal mathematical methodology to apply across all utilities or all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases, including movement toward allocated cost of service and maximum/minimum percentage changes across individual rate classes.

Q: Please provide a summary of the Company's proposed class revenue increases.

A: As part of its supplemental filing, the Company is requesting a total jurisdictional increase of $143.627 million, which represents an increase of 7.32 percent.[14] The following table provides a summary of each class' current revenues, PSE's proposed increase, and PSE's proposed percentage increase:

Table 5
PSE Proposed Rate Spread
($000)

Class		Current Revenue	PSE Proposed Increase	Percent Increase	% of Jurisdictional Average
Jurisdictional:					
7	Residential	$1,066,627	$87,074	8.16%	112%
24	Secondary <50kw	$266,944	$16,344	6.12%	84%
25/29	Secondary >50kw and <350kw	$252,923	$15,486	6.12%	84%
26	Secondary >350	$151,835	$9,296	6.12%	84%
31	Primary	$101,395	$6,208	6.12%	84%
35	Irrigation	$248	$15	6.12%	84%
43	All Electric Schools	$10,338	$844	8.16%	112%
40	Campus	$47,837	$4,036	8.44%	115%
46/49	High Voltage	$40,360	$2,471	6.12%	84%
449/459	Retail Wheeling	$7,513	$451	6.00%	82%
50/59	Lighting	$17,167	$1,401	8.16%	112%
Total		$1,963,187	$143,627	7.32%	100%
Non-Jurisdictional:					
5	Firm Resale	$316	$405	128.05%	1,750%
Total		$1,963,503	$144,032	7.34%	100%

Q: What was Mr. Piliaris' claimed method or approach to assign revenue increases to individual classes?

A: Generally, Mr. Piliaris indicates that for those classes with current parity ratios greater than 105 percent, these classes were increased at 75 percent of the adjusted average percentage increase to the retail classes. For those classes within five percent of parity,

[14] Under the Company's proposal, its total required increase is $144.032 million. However, this includes a small amount of non-jurisdictional resale revenues in which the Company proposes to impute an increase of $0.405 million to bring this non-jurisdictional class up to cost of service. As a result, the jurisdictional requested increase is $143.627 million.

these classes were all increased by an equal percentage. Mr. Piliaris also notes that there were three exceptions to his method. First, Rate Schedule 40 was not independently determined, as this rate schedule's production and transmission charges have historically been linked to those of the High Voltage schedules (Rate Schedules 46/49).[15] Second, Mr. Piliaris increased non-jurisdictional resale customers to full cost of service. Mr. Piliaris does not discuss the third option; however, this will be described below.

Q: Are PSE's proposed class revenue increases (rate spread) fair and reasonable?

A: No. First, I will describe the exception to Mr. Piliaris' method that he does not discuss. As shown in Table 5 above, Mr. Piliaris proposes to increase the Choice/Retail Wheeling class (Rate Schedules 449/459) by only 82 percent of the jurisdictional system average. In fact, under the Company's proposal, this class would incur the smallest percentage increase of any class. However, if we consider this class' parity ratio shown in my Table 4, we see that this class' parity ratio is significantly deficient, i.e., between 65 percent and 67 percent. Given the desire to move those classes with parity ratios significantly below 100 percent closer to system parity, I see no reason for this class to sustain a significantly smaller increase than the jurisdictional system average. Indeed, this class' parity ratio is so low that I recommend rates for this class be increased by 150 percent of the jurisdictional system average (10.97 percent).

Next, Mr. Piliaris' selection of +/- five percent is too narrow given this Commission's prior practice of using a +/- 10 percent parity band for evaluating revenue responsibility. As discussed throughout my testimony, class cost of service studies are not surgically precise. Indeed, alternative studies show that the Residential class' parity

[15] Schedule 40's distribution charges are customer-specific.

ratio is between 96 percent and 99 percent. However, Mr. Piliaris proposes to increase the Residential class revenues by more than the jurisdictional system average (112 percent of jurisdictional system average). Similarly, several other classes have calculated parity ratios very close to 100 percent, albeit slightly higher. For example, the General Service Secondary Voltage <50 kW class (Rate Schedule 24) has parity ratios between 106 percent and 108 percent, yet Mr. Piliaris proposes to increase this class by only 84 percent of the jurisdictional system average percentage increase.

Q: Do you recommend alternative class revenue increases to those proposed by PSE?

A: Yes. Three classes exhibit parity ratios that are significantly below 100 percent under all CCOSS conducted: Irrigation, Retail Wheeling, and Non-Jurisdictional Resale. All other classes have parity ratios within +/- 10 percent of unity. As discussed earlier, the three classes with parity ratios below 100 percent are significantly deficient: Irrigation is between 48 percent and 61 percent; Retail Wheeling is between 65 percent and 67 percent; and, Non-Jurisdictional Resale is between 48 percent and 50 percent. With regard to Non-Jurisdictional Resale business, I agree with Mr. Piliaris that this non-jurisdictional business should be priced at full cost of service as reflected in the Company's proposed supplemental revenue requirement. With regard to Irrigation and Retail Wheeling, these classes are so revenue deficient, I recommend increasing their revenues at 150 percent of the jurisdictional system average percentage increase, or by 10.97 percent. These parity ratios still remain significantly below 100 percent even with my proposed adjustments, yet my proposal will induce some movement toward system parity.[16]

With regard to the other jurisdictional classes, all classes currently exhibit parity ratios within a 10 percent band of unity. As such, I recommend an equal percentage increase to all other classes (7.30 percent). Table 6 below provides my recommended class rate spread at the Company's requested $143.627 million jurisdictional increase:

Table 6
Public Counsel Proposed Rate Spread
($000)

Class		Current Revenue	PC Proposed Increase	Percent Increase	% of Jurisdictional Average
Jurisdictional:					
7	Residential	$1,066,627	$77,880	7.30%	99.8%
24	Secondary <50kw	$266,944	$19,491	7.30%	99.8%
25/29	Secondary >50kw and <350kw	$252,923	$18,467	7.30%	99.8%
26	Secondary >350	$151,835	$11,086	7.30%	99.8%
31	Primary	$101,395	$7,403	7.30%	99.8%
35	Irrigation	$248	$27	10.97%	150.0%
43	All Electric Schools	$10,338	$755	7.30%	99.8%
40	Campus	$47,837	$3,493	7.30%	99.8%
46/49	High Voltage	$40,360	$2,947	7.30%	99.8%
449/459	Retail Wheeling	$7,513	$825	10.97%	150.0%
50/59	Lighting	$17,167	$1,253	7.30%	99.8%
Total		$1,963,187	$143,627	7.32%	100.00%
Non-Jurisdictional:					
5	Firm Resale	$316	$405	128.05%	--
Total		$1,963,503	$144,032	7.34%	--

Q: Under your proposed class rate spread, are the Campus Rate Schedule 40 production and transmission charges linked to the High Voltage Rate Schedules 46/49?

[16] The Irrigation parity ratio will increase from about 50 percent to 54 percent, while the Retail Wheeling parity ratio will increase from about 67 percent to 71 percent.

A: No. In the Company's 2004 general rate case (Docket No. UE-040640), Microsoft requested and negotiated a special "Campus" rate in which this customer would be directly-assigned and responsible for distribution facilities serving its various locations. Moreover, the distribution charges imposed upon Campus Rate 40 do not necessarily follow traditional ratemaking practices and use a somewhat levelized revenue recovery approach. Nonetheless, the distribution charges to Campus Rate 40 are customer-specific. Then, in order for the Company to recover its production and transmission-related costs from Microsoft, it was negotiated that production and transmission-related charges would simply be tied to the High Voltage Rates Schedule 46/49. Because the High Voltage class does not rely upon the Company's distribution facilities, the charges for the High Voltage (transmission) class were an easy way for the Company to "unbundle" Campus Rate Schedule 40 rates between distribution and production/transmission charges.

Remembering that the Campus Rate Schedule 40 was developed as a totally new rate schedule at the request of Microsoft, there is no compelling reason why this class' production and transmission charges should be necessarily wed to those of another class. Indeed, Campus Rate Schedule 40 customers have enjoyed the benefits of directly-assigned distribution costs and at the same time, enjoy the production/transmission rates available to much larger transmission customers. Because Campus Rate Schedule 40 is a completely separate rate schedule, and was requested by the customer, this class' production and transmission charges should be determined independently.

Q: Have you examined the usage and load characteristics of Campus Rate Schedule 40 customers to those of High Voltage customers?

A: Yes. Based on the Company's supplemental filing, the average Campus Rate Schedule 40 customer utilizes 4,269,646 kWh per year, while the average Firm High Voltage customer uses 28,399,193 kWh per year. As such, the average Campus Rate Schedule 40 customer is only about 15 percent as large as the average Firm High Voltage customer. In addition, and in response to Public Counsel Data Request No. 300, I examined the load characteristics of Rate Schedule 40 and Rate Schedule 49 (Firm High Voltage service). In examining this data, I observed that Campus Rate 40 customers are more weather sensitive than High Voltage customers and have a higher heating and cooling load than do High Voltage customers based upon these customers' loads during the cold winter and warmer summer months compared to the milder spring and fall months. As a result, Campus Rate Schedule 40 customers rely upon the Company's production and transmission facilities relatively more during peak periods than do High Voltage Firm customers. Moreover (during the test year), High Voltage Firm customers exhibited a higher non-coincident load factor than the Campus Rate 40 class (78 percent vs. 67 percent). When all factors are considered, along with the fact that Microsoft wanted a separate rate schedule unique to its facilities, there is no compelling reason that the Campus Rate Schedule 40 production/transmission charges should be tied to an industrial High Voltage rate schedule. As such, I recommend that the production/transmission charges for Campus Rate Schedule 40 be independently determined based upon the rate spread I recommend in this case.

Q: The class rate spread you have discussed and presented in your Table 6 reflects the Company's requested jurisdictional increase of $143.6 million. Should the Commission authorize an increase less than the amount requested by PSE, how do you recommend the overall authorized increase be spread across jurisdictional classes?

A: I recommend that my class rate spread proposal presented in Table 6 be scaled-back proportional to my proposed increases.

C. Electric Rate Design

Q: Please explain PSE's current Residential rate structure.

A: Currently, PSE's Rate Schedule 7 is comprised of a fixed monthly customer charge plus an inverted two-block energy charge. Under current rates, the base monthly customer charge is $7.49 and an additional $0.38 collected through Schedule 141 (Expedited Rate Filing). With regard to the current inverted-block rate, there is about a $0.02 differential between the first usage block (first 600 kWh) and the second usage block (above 600 kWh).

1. Customer Charges

Q: Is PSE proposing to increase the Residential fixed monthly customer charge?

A: Yes. Company witness Piliaris proposes to increase the Residential customer charge to $9.00 per month in this case.

Q: How does Mr. Piliaris support the proposed increase to the Residential fixed monthly customer charge?

A: Mr. Piliaris provides four justifications for his proposed customer charge of $9.00 per month. First, he indicates that the true, or effective, fixed monthly customer charge is currently is $7.87 due to the $0.38 fixed charge imposed under Schedule 141 (this compares to the base rate charge of $7.49). Second, Mr. Piliaris states that the current charge has effectively been in place since 2012 such that "it is reasonable to expect there would have been cost growth in the intervening time." Third, Mr. Piliaris claims that his cost of service study indicates a customer cost exceeding $11.00 per month. Finally, Mr. Piliaris opines that the current rate plan in effect since 2013, which provided for three percent annual increases, were collected totally through volumetric charges rather than spread across both volumetric and fixed charges due to the settlement establishing the rate plan. Absent this settlement, Mr. Piliaris implies that the annual rate plan increases would have further increased the base fixed monthly customer charges during the rate plan.

Q: Please respond to Mr. Piliaris' justifications for his proposed $9.00 monthly Residential customer charge.

A: But for his customer cost calculations, Mr. Piliaris' justifications relate to the time elapsed between the last rate case and the effects of various settlements. Indeed, Mr. Piliaris is correct in these regards. Time has certainly passed since 2012, but what is most important is that the customer charges in effect now and for the last several rate cases have been the result of settlements. Public Counsel has agreed to higher customer charges than it (or I) would have preferred, but in the interest of settling all issues, Public Counsel and the Company agreed to the current customer charge levels in the spirit of compromise. As such, I see little merit in the timing and settlement justifications offered by Mr. Piliaris. With respect to Mr. Piliaris' opinion that the Residential customer cost exceeds $11.00 per month, one must investigate what "costs" Mr. Piliaris included in his Residential customer cost analysis.

Q: Do you agree with Mr. Piliaris' customer cost analysis?

A: No.

Q: Please explain why you do not agree with Mr. Piliaris' customer cost analysis.

A: On page 14 of Exhibit No. JAP-7, Mr. Piliaris presents a summary of the results of his customer cost analysis that produces a Residential customer cost of $11.24 per month. A closer examination of Mr. Piliaris customer cost analysis reveals that he included provisions for various capital costs, including return and depreciation, and operating and maintenance expenses. However, Mr. Piliaris' analysis inappropriately includes many costs that should not be deemed customer-related for purposes of evaluating the reasonableness of residential customer charges.

Q: Please identify the capital costs that Mr. Piliaris included in his customer cost analysis.

A: Mr. Piliaris' analysis includes the allocated Residential gross plant investments in Meters ($88.5 million), Services ($175.6 million), Distribution Line Transformers ($333.2 million), and an allocated portion of General plant ($74.3 million).

Q: Are these rate base, or capital items, appropriately included in a customer cost analysis?

A: No. Investments in Meters and Services are often included in traditional customer cost analyses. However, as I will discuss in more detail later, PSE's customer connection fees already contain a provision for service line investments such that all new customers must pay for the total costs (materials and labor) associated with the installation of service lines.

Mr. Piliaris' inclusion of Line Transformer costs is at odds with virtually every accepted industry standard and practice. Indeed, nearly every manual and text on the subject of electric cost of service properly considers line transformers as demand-related. Mr. Piliaris' rationale for including transformers is solely based on every distribution customer being connected to a transformer and that, once installed, transformers represent a fixed cost of providing service to the customer or group of customers connected to the transformer. This rationale is meaningless since it could be extended to all distribution lines, substation equipment, and even transmission lines. Moreover, the fundamental reason that transformers should not be considered customer-related is because they are sized and installed based on peak load requirements. Transformers reduce distribution voltage and are limited in capacity based on the maximum load going through each transformer. If customers were simply connected to a distribution system with no loads, there would be no need for transformers.

Finally, Mr. Piliaris has included $74.3 million in General plant in his customer cost analysis. This General plant allocation represents the Company's investment in corporate overhead required to provide electricity sales to customers. This general overhead is needed to support PSE's electric operations, which is selling electricity to customers. In fact, the level of General plant included Mr. Piliaris' Residential customer costs includes the following gross plant amounts:

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Table 7
PSE General Plant Investment
($ Millions)

Land and Land Rights	$5.9
Structure & Improvements	$24.0
Office Furniture	$14.3
Transportation Equipment	$2.3
Stores Equipment	$0.1
Tools, Shop and Garage Equipment	$0.9
Laboratory Equipment	$0.8
Power Equipment	$0.4
Communications Equipment	$25.2
Miscellaneous Equipment	$0.2
Other Property	$0.1
TOTAL	$74.3

Table 7 demonstrates that the vast majority of the General plant that Mr. Piliaris assigns to customers relates to corporate office buildings, furniture, and communications equipment. Because General plant represents the overhead investment required to conduct its public service obligations of selling electricity, such costs should not be considered in a customer cost analysis for purposes of justifying fixed customer charges.

Q: What Operations and Maintenance (O&M) expenses did Mr. Piliaris include in his customer cost analysis?

A: Mr. Piliaris' Residential customer costs analysis includes allocations for the following O&M expenses:

- Distribution Supervision and Engineering ($0.2 million),
- Meters Operations Expenses (-$0.6 million),
- Customer Installation Expenses ($3.0 million),
- Line Transformers Maintenance Expenses ($0.2 million),
- Meters Maintenance Expenses ($0.3 million),
- Customer Accounting Supervision ($9.3 million),

- Meter Reading ($22.2 million),
- Customer Records & Collections Expenses ($12.2 million), and
- Administrative and General Expenses ($16.6 million).

Q: Are each of these O&M expenses properly included in a customer cost analysis?

A: No, some of the expenses are, but many are not. From their descriptions, many of the O&M costs included by Mr. Piliaris represent costs that are more appropriately considered demand-related (e.g., transformer expenses) or are general overhead expenses required in order to sell electricity. Meter Reading and Customer Records & Collections expenses are properly included in Mr. Piliaris' customer cost analysis.

Q: What is your overall assessment of Mr. Piliaris' Residential customer costs analysis?

A: Mr. Piliaris' Residential customer cost analysis greatly overstates the costs that should be considered in establishing a reasonable fixed monthly customer charge. Because PSE is in the business of selling electricity and not in the business of simply connecting customers, only those costs that can be directly attributed to connecting and servicing a customer's account should be included in such analysis.

Q: Earlier you indicated that Residential customers are responsible for all capital costs associated with service lines. Please explain.

A: Electric Tariff G, Schedule 85 contains PSE's policy regarding line extensions and connection fees for new customers. In general, PSE charges new customers a connection fee based on the following formula:

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+ Primary Voltage Lines Extension Costs
+ Secondary Voltage Lines Extension Costs
+ Exceptional Transmission & Substation Costs
- Margin Allowance
= Line Extension Cost
+ Service Line Costs
= Total Cost to Customer

These line extension costs include, at a minimum, the estimated cost to install conductors (excluding service lines) and transformers. Notably, the margin allowance provided by the Company does not include the cost of service lines, meaning that customers are responsible for the costs of installing service lines to their meters. PSE charges customers a non-refundable connection fee for all service line costs, as well as the line extension costs above the prescribed margin allowance. Estimated construction costs differ for underground and overhead service while the margin allowance is constant for both underground and overhead customer service.

Q: How do these new customer connection fees relate to customer charges?

A: As discussed earlier, Mr. Piliaris has included the Company's allocated investment in Services and Line Transformers in his customer cost analysis. Although the Company's Schedule 85 margin allowance may be sufficient to cover the costs associated with installing new transformers (or connecting to existing facilities), all new customers pay for the costs of labor and materials to install a service line. As such, a higher customer charge as proposed by Mr. Piliaris represents a double cost to new customers.

Q: What costs should be considered in evaluating the level of appropriate customer charges?

A: Only those direct costs required to connect and maintain a customer's account should be considered. These costs generally include the capital costs associated with Meters and

Services as well as the O&M expenses associated with Meters, Meter Reading, and Customer Records & Collections.

Q: Has this Commission recently provided guidance as to the level of costs that should be considered when establishing Residential customer charges?

A: Yes. In the 2015 PacifiCorp rate case (Docket UE-140762), Company witness Steward conducted a customer cost analysis similar to that performed by Mr. Piliaris in this case. Ms. Steward's customer cost analysis included the costs associated with line transformers as well as a myriad of other overhead costs. Staff witness Twitchell also conducted a customer analysis that excluded several of the overhead costs included by Ms. Steward but did include the costs associated with transformers.[17] On behalf of Public Counsel, I conducted a direct customer cost analyses, which excluded the costs of transformers as well as other overhead costs.

In its Final Order, the Commission determined:

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. **The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing.** Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals. **[Emphasis added]**[18]

Q: In this case, have you conducted an electric Residential customer direct cost analysis similar to the analysis you conducted in the 2015 PacifiCorp rate case that was approved by the Commission?

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[17] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co*., Docket UE-140762, Final Order No. 08 at 86- 87 (Mar. 25, 2015).

[18] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co*., Docket UE-140762, Final Order No. 08 ¶ 216 (Mar. 25, 2015).

A: Yes. I have conducted a direct customer cost analysis, which I present in Exhibit No. GAW-11. As shown in this Exhibit, I calculated the direct Residential customer cost with and without the inclusion of Services cost as well as under current and Company proposed depreciation rates. Furthermore, in conducting my customer cost analysis, I utilized the Company's proposed cost of capital (7.74 percent), which reflects a return on equity of 9.80 percent. My analysis produces a direct Residential customer cost between $4.05 and $5.61 per month at the Company's requested rate of return. As a point of comparison, if the authorized return on equity is reduced to 9.00 percent, my analysis produces a direct Residential customer cost between $4.02 and $5.54 per month.

Q: Notwithstanding the costs that should be considered in determining customer charges, are there public policy issues concerning the level of fixed monthly customer charges?

A: Yes. High fixed charges are contrary to conservation-related goals and promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well known Order 636, the Federal Energy Regulatory Commission's (FERC's) adoption of a "Straight Fixed Variable" ("SFV") pricing method[19] was the result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. FERC's SFV pricing mechanism greatly reduced the price of incremental (additional)

[19] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.

natural gas consumption. This resulted in significantly increased demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[20] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated, "The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil…."[21] With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[22]

Recently, some public utilities have begun to advocate SFV Residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily

[20] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 at 7 (Apr. 9, 1992).
[21] *Id.,* at 8 (alteration in original).
[22] *Id.,* at 128-129.

based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q: As a public policy matter, what is the most effective tool that regulators have to promote cost effective conservation and the efficient utilization of resources?

A: Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is to develop rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that consists of high fixed charges results in effective prices that do not properly vary with consumption, and instead promote inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are far inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q: What is your recommendation as to Residential monthly customer charges for PSE in this case?

A: Given the results of my Residential monthly direct customer cost studies indicating a monthly customer cost range from $4.02 to $5.61, there is no reason to increase PSE's base monthly customer charge of $7.49. In fact, there is reasonable justification for the Commission to reduce the fixed charge to under $6.00 per month. However, for rate continuity, I recommend a Residential monthly customer charge of $7.50.[23]

2. Residential Energy Charges

Q: Have you investigated PSE's rate structure as it relates to Residential energy charges?

[23] My $0.01 increase recommendation is simply due to rounding that, in my opinion, results in a more logical rate.

A: Yes. As indicated earlier, PSE's Residential energy charges consist of a non-seasonally differentiated inverted two-block rate structure. The Commission adopted a settlement in Docket UE-141368 that required presentation of an inverted three-block rate structure for residential customers. Although parties to the settlement approved by the Commission in Docket No. UE-141368 have agreed to not be required to support a proposal for an inverted three-block rate structure, I have investigated the advantages and disadvantages of changing the current two-block rate structure to an inverted three-block rate structure as well other possibilities.

Originally, Commission Staff advanced a proposal to change PSE's Residential electric rates to an inverted three-block rate structure as a means to send price signals to more effectively promote conservation and dissuade the "wasteful" use of electricity. As an economist, I view conservation as the efficient utilization of resources and not simply a reduction in the use of resources. Furthermore, the concept of "wasteful" is very subjective in nature. For example, on one hand, a household that uses electricity to heat their swimming pool could be considered wasteful by some simply because it may be considered a luxury. On the other hand, this type energy use may seem to be prudent and necessary by others in order to use that swimming pool. Clearly, it is easy to imagine other subjective examples of what might be wasteful: electricity required to heat a large home compared to the electricity required to heat a smaller home, electricity used for air conditioning in Washington's temperate climate, etc.

In terms of the efficient utilization of resources as a proper standard for promoting conservation, economic theory and principles indicate that prices should be based on marginal cost. However, this Commission may also want to consider the social and public policy as they related to affordability, impacts on low-income customers, policies concerning reductions to carbon emissions, and equity and fairness to all ratepayers. As such, economic efficiency can and often does conflict with the needs of society in general.

I reviewed Mr. Piliaris' testimony as it relates to PSE's development of a three-block rate structure for the Residential class. In this regard, I agree with Mr. Piliaris that from an economic standpoint, any such tail-block should be based on long-run marginal (avoided) costs. Mr. Piliaris' analysis shows that the Company's calculated avoided cost per kWh would result in a third tail-block rate actually lower than the current second usage block rate. As such, under the three-tiered rate structure developed by Mr. Piliaris, the tail-block rate would be priced below the second usage block rate, which would be counter to the objectives promulgated by Commission Staff.

From a social perspective, several questions arise:

- Is a truly inverted three-block rate structure in the best public interest?
- What impacts will this have on various customers within the Residential class?
- Will an intentionally high-priced third-block rate be discriminatory to certain Residential users?

Indeed, if an inverted third tail-block is developed intentionally at a higher price to simply discourage usage by large customers, it may be viewed as a punitive pricing policy. With these observations and questions, I have investigated the number of customers that use relatively large amounts of electricity, as well as the number of customers that use relatively little electricity, in order to evaluate the potential impact on the Residential class. In addition, I analyzed the usage patterns of PSE's Residential customers based on their average and peak monthly usage patterns.

Q: The settlement and Order in Docket No. UE-141368 contemplated the feasibility of adding a third tail-block with usage greater than 1,800 kWh per month. Have you investigated the number of customers that use this level of energy?

A: Yes. In Public Counsel Data Request No. 432, the Company provided a database of every Residential locational bill during the test year, i.e., every bill by address. This database included 997,127 total unique customer locations with more than 11 million[24] individual observations. In conducting my analysis, I eliminated those customer locations in which there was less than 25 kWh for any given month. This enabled me to evaluate those records that realistically use electricity on a consistent basis. By eliminating records with less than 25 kWh in any month, a database consisting of 951,071 customer-specific locations was used for my analysis (a total of 11,412,852 records).

My first area of investigation was to determine when and to what extent Residential customers used more than 1,800 kWh per month. The following table provides a summary by month of the number and percentage of customers who used more than 1,800 kWh per month:

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[24] 997,127 locations x 12 months.

Table 8
Residential Usage Greater Than 1,800 kWh
(Number of Bills)

Month	No. of Bills	% of Total No. of Bills
Jan.	177,798	18.7%
Feb.	105,513	11.1%
Mar.	92,509	9.7%
Apr.	35,932	3.8%
May	27,127	2.9%
June	22,400	2.4%
July	26,463	2.8%
Aug.	29,916	3.1%
Sept.	21,778	2.3%
Oct.	43,549	4.6%
Nov.	122,012	12.8%
Dec.	194,783	20.5%

As Table 8 demonstrates, about 20 percent of Residential customers utilized more than 1,800 kWh in the cold winter months of December and January with only two percent to three percent of the customers using this level of energy during the summer months.[25]

Next, I evaluated the propensity for individual customers to use more than 1,800 kWh on a monthly basis throughout the year. In other words, I tabulated the number of customers that used more than 1,800 kWh for at least one month, at least two months, at least three months, etc. These amounts and percentages are shown in Table 9 below:

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[25] In this regard, the database provided in response to Public Counsel Data Request No. 432 reflects actual test year usage. However, the winter months of the test year were rather mild such that somewhat higher percentages may be likely under more normal weather conditions.

Table 9
Residential Usage Greater Than 1,800 kWh
(Monthly Use Greater Than 1,800 kWh)

Month	No. of Bills	% of Total No. of Bills
At least 1 month	214,216	22.5%
At least 2 months	181,039	19.0%
At least 3 months	134,795	14.2%
At least 4 months	107,207	11.3%
At least 5 months	85,729	9.0%
At least 6 months	48,732	5.1%
At least 7 months	35,142	3.7%
At least 8 months	26,491	2.8%
At least 9 months	21,341	2.2%
At least 10 months	18,112	1.9%
At least 11 months	15,142	1.6%
All 12 months	11,832	1.2%

As indicated above, about 23 percent of all Residential customers used more than 1,800 kWh at least one month during the year while about 9.0 percent of all Residential customers used more than 1,800 kWh for five or more months of the year. Only 1.2 percent of the customers used more than 1,800 kWh every month of the year.

The above information and statistics indicate the number and degree to which Residential customers use more than 1,800 kWh per month. However, this does not adequately evaluate how consistently larger usage customers use electricity throughout the year. In my opinion, the consistency (or lack thereof) of usage is a critical factor in evaluating the cost imposed upon PSE as well as those costs indirectly imposed upon other Residential customers. In other words, customers who use a large amount of electricity in one month, but relatively little electricity in all other months, can cause additional cost to Company (and ultimately all other customers), particularly if this customer’s high usage occurs during a peak period, i.e., during a cold winter month.

Conversely, if a large customer uses electricity consistently throughout the year, it can be said that this customer uses electricity in a rather efficient manner such that the cost to serve this customer are spread throughout the year in that this customer's load curve is generally much flatter thereby maximizing the utilization of the Company's resources (facilities).

While individual customer kW demands are not known, I was able to evaluate each customer's average monthly usage throughout the year relative to its peak monthly usage. Although not technically correct, I will define this ratio of average monthly usage to peak monthly usage as a so-called "load factor" for purposes of this discussion. PSE's system and Residential peak loads invariably occur during November, December, or January. Indeed, each of these month's usages are considerably higher than the spring, summer, or fall months. As such, I evaluated the so-called load factors of those customers that used more than 1,800 kWh per month in any of the months of November, December, or January. There were 206,254 customers that used at least 1,800 kWh in any one of these three months with an average usage of 1,661 kWh over this three-month period.[26] The average peak use was 2,761 kWh, which results in an overall so-called load factor of 60 percent. Next, I evaluated the distribution of the so-called load factors and separated these into six strata as shown in the table below:

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[26] These 206,254 customers represent about 22 percent of all Residential customers.

Table 10
Average Month to Peak Month Usage
For Those Customers Using More Than 1,800 kWh Per Month
In Any Month During November, December, or January

Avg. Mth./Peak Mth Ratio	Number of Customers	Percent
< 25%	97	0.1%
≥ 25% < 35%	1,278	0.6%
≥ 35% < 50%	29,493	14.3%
≥ 50% < 65%	113,659	55.1%
≥ 65% < 80%	50,760	24.6%
≥ 80%	10,967	5.3%
Total	206,254	100.0%

As shown above, about 85 percent of these customers who use more than 1,800 kWh during any winter month have a so-called annual load factor of at least 50 percent. Furthermore, about 30 percent of the customers have a so-called load factor of at least 65 percent. This distribution of large volume users indicates that as a group, large users are not significantly inefficient, at least in terms of using electricity (and the Company's facilities) throughout the year.

Q: What are your conclusions regarding the number of large volume Residential customers as well as their usage characteristics throughout the year?

A: There is a relatively large percentage of customers utilizing at least 1,800 kWh at some point in time during the year and about 22 percent of all customers use this amount of electricity during at least one or more of the winter months. Furthermore, while there are some customers who use a large amount of electricity for only a few months of the year, the majority of customers using more than 1,800 kWh in the winter months tend to have a reasonably adequate load factor, where they use energy reasonably consistently throughout the year. In this regard, it should be understood that the numbers presented above are not necessarily indicative of the number of customers that would be impacted by a high-priced third tier-block. This is because under a three-tier inverted rate design where the tail-block is priced at a high level, the first two usage block rates would be priced lower than they would be under a two-tiered rate structure. Therefore, only those customers using considerably more than 1,800 kWh per month would be materially impacted under such a rate design. However, the number and degree to which large volume Residential customers would be impacted would, of course, depend on the price level of the third tail-block, as well as the rate differential between the first, second, and third blocks.

Q: Have you also evaluated the number of small volume users as well as their usage characteristics throughout the year?

A: Yes. Similar to the analyses conducted for large Residential users (i.e., usage greater than 1,800 kWh per month), I also evaluated those customers who use relatively little electricity. Specifically, I evaluated those customers with usage less than 600 kWh. 156,448 Residential customers (16 percent of all customers) used less than 600 kWh for every month of the test year. Furthermore, 183,233 customers (19 percent) used less than 600 kWh during all three winter months of November, December, and January. The distribution of the load factors for small volume customers is presented in the table below:

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Table 11
Average Month to Peak Month Usage
For Those Customers Using Less Than 600 kWh Per Month

Avg. Mth./ Peak Mth Ratio	Distribution of Customers: < 600 kWh All Months	Distribution of Customers: < 600 kWh All Winter Months
< 25%	0.1%	0.1%
≥ 25% < 35%	0.4%	0.6%
≥ 35% < 50%	4.1%	5.2%
≥ 50% < 65%	16.9%	19.3%
≥ 65% < 80%	45.7%	45.1%
≥ 80%	32.9%	29.7%
Total	100.0%	100.0%

In general, these small volume users have a somewhat higher so-called load factor than higher volume users. This is demonstrated by comparing the distribution of high usage to low usage customer so-called load factors. Such a finding is expected since small volume customers tend to be much less weather sensitive than high usage customers in that they do not tend to rely on electricity for heating as much as higher volume customers.

Q: You have indicated that PSE is a winter peaking utility and that Residential customers invariably use significantly more electricity during the winter months than other seasons of the year. Have you investigated the seasonal and hourly load characteristics of Residential customers on a seasonal basis?

A: Yes. I evaluated total Residential hourly loads during the summer months as well as during the winter months. For the highest 25 system hourly loads during the winter, the average Residential load was 2,531 mW. During the 25 highest hourly system loads during the summer months, the average Residential load was 1,492 mW. Therefore, during peak seasonal hours, the summer Residential load is only about 59 percent of that experienced during winter peak periods. Furthermore, I observed that there are distinct Residential peak periods within the winter and summer months. During the winter, there are two distinct diurnal system peak periods: one from about 6 a.m. to about 9 a.m. and another from about 5 p.m. to about 7 p.m. However, the Residential class tends to peak during the late afternoon between about 5 p.m. and 8 p.m. in the winter months.[27] During the summer months, the diurnal system peak tends to occur in the afternoon between about 4 p.m. and 6 p.m., although there are some significant system peak demands earlier in the afternoon between 2 p.m. and 4 p.m. The Residential summer peaks tend to occur between 5 p.m. and 7 p.m.

Q: What are your findings regarding the seasonal use and load characteristics of the Residential class?

A: Residential seasonal loads tend to be fairly coincident with system loads such that the Residential class tends to peak at about the same time as the system both during the summer and winter. However, during the winter, the Residential class tends to not have as much of a morning peak load as the system. Perhaps most important, is the fact that Residential peak loads in the winter are almost 60 percent more than peak loads during the summer months.

Q: What are your overall conclusions regarding the structure of PSE's Residential energy charges?

A: At this time, I can see no reasonable economic reason to initiate a third tail-block for PSE. I base my conclusion on (1) the usage characteristics of PSE's large volume

[27] In this regard, there also tends to be significant Residential loads occurring about between 7 a.m. and 9 a.m., albeit not as high as the later afternoon.

Residential customers (usage greater than 1,800 kWh) compared to all customers, (2) the usage characteristics of PSE's relatively small customers who use small amounts of electricity, (3) PSE's calculated avoided cost, and (4) the additional complexity resulting from an additional usage block within the rate design.

However, in the interest of sending pricing signals that are both cost-based and efficient in terms of resource conservation, the Commission may want to consider studying the establishment of seasonal rates for the Residential class. While I have not developed specific seasonal rates, I would envision a rate structure comprised of an inverted two-block summer rate and an inverted two-block winter rate wherein the winter tail-block rates are priced higher than the summer tail-block rates. My load and usage data is not weather normalized and does not coincide with the billing determinants utilized by PSE in this case. In this regard, and to the extent the Commission is interested in pursuing the possibility of seasonal rates, a somewhat different blocking structure may be warranted, i.e., for example, the usage block including up to 800 kWh per month. An alternative blocking structure comprised of a first usage block higher than the current 600 kWh usage block may be priced in the context of a low "life line" rate. This in turn could assist customers in affording the most basic level of electricity usage.

3. Tariff Changes

Q: Do you recommend any changes to the Company's electric tariff?

A: Yes. In reviewing the Company's electric rate schedules, specifically, Residential Rate Schedule 7, I observed that it is virtually impossible for a customer to determine the total price (rates) that they must pay for electricity. Rate Schedule 7 only sets forth the base rates but then states, "[R]ates in this schedule are subject to adjustment by such other schedules in this tariff as may apply." As a practicing rate economist, I consider myself reasonably competent in evaluating what consumers' must pay for electricity. However, I can represent to this Commission that I have not been able to fully determine the "all in" price that Residential customers must pay for electricity. This is because, PSE's tariff includes numerous billing adjustment or rider schedules including: Schedule 81 (Tax Adjustment); Schedule 95 (Power Cost Adjustment); Schedule 95A (Federal Incentive Tracker); Schedule 120 (Electric Conservation Service Rider); Schedule 129 (Low Income Program Rider); Schedule 132 (Merger Rate Credit); Schedule 133 (Sale of Asset Tracker); Schedule 137 (Temporary Customer Charge/Credit); Schedule 140 (Property Tax Rider); Schedule 141 (Expedited Rate Filing Rate Adjustment Rider); Schedule 142 (Revenue Decoupling Adjustment); and, Schedule 194 (Residential and Farm Energy Exchange Credit).

Notwithstanding the voluminous number of adjustment riders, it is often difficult, if not impossible, for a Residential customer to determine the rates associated with each of these riders and how it will affect their electricity bill relative to their consumption. Even if a customer were able to understand each adjustment rider as well as the rate associated with Residential service, that customer must add up a myriad of various adjustments to determine its "all in" price of electricity. Such an exercise is unduly burdensome for any customer to understand the price they must pay for electricity. In my opinion, this is a major shortcoming of the Company's tariff given that this Commission has stated a clear policy preference to send accurate pricing signals to customers. In other words: one may ask how customers can receive adequate pricing signals if they do not know their "all in" price of electricity. In this regard, I recommend this Commission order the Company to provide a summary sheet within its tariff that provides the "all in" price of electricity (including the "all in" price by volumetric usage block).

III. NATURAL GAS OPERATIONS

A. Natural Gas Cost of Service

Q: Have you examined PSE's natural gas CCOSS sponsored by Mr. Piliaris in this case?

A: Yes.

Q: Please briefly describe the general methodology utilized within Mr. Piliaris natural gas CCOSS.

A: By far, the most controversial aspect relating to natural gas cost allocation studies concerns the methodologies and approaches used to allocate distribution mains across customer classes. In this case, Mr. Piliaris has utilized the general methodology known as the Peak & Average approach wherein he has allocated mains based partially on annual throughput (average day demand) and peak demand. Moreover, Mr. Piliaris used a system load factor of 33 percent to weight the allocation between average day and peak day usage. Furthermore, Mr. Piliaris separated mains by various pipe sizes and allocated these various sizes of mains differently across customer classes based on small, medium, and large diameter mains.

Q: Did Mr. Piliaris use the same methodology in this case as used by PSE in prior rate cases?

A: Yes. Mr. Piliaris' method is the same going back to the 2009 general rate case (Docket No. UG-090705). However, as will be discussed below, the current methodology utilized by Mr. Piliaris reflects a compromise of various experts' philosophies and positions as to how distribution mains should be allocated across classes.

Q: Please provide a history of CCOSS issues concerning PSE's natural gas operations.

A: In early 2009, a collaborative was formed to investigate various cost allocation methodologies relating to PSE's natural gas operations and to determine if any joint resolutions could be made by the various parties participating in the collaborative.

As with most natural gas local distribution CCOSS, there had historically been considerable disagreement and controversy centered around the assignment of distribution mains, plant, and related costs to individual rate classes. These disagreements and controversies have stemmed from the fact that with rare exception, the specific mains investment required to serve a particular customer or group of customers cannot be isolated or specifically identified. As such, the vast majority of distribution mains represent joint costs in which PSE's investment in mains serves the collective need of all customers. Furthermore, there are definite economies of scale present in LDC systems (including PSE's) such that all customers reap the benefits of system-wide costs, i.e., the cost to serve any customer collectively in the system is less than to serve the customer on a stand-alone basis.

As a result of various experts' opinions, whose views are often diametrically opposed regarding the proper assignment of mains costs, the 2009 collaborative and study group attempted to resolve these issues. While the collaborative did not reach agreement on a mains allocation method or even a philosophical consensus as to cost causation, each party's views were debated and clearly understood. In short, I believe it is fair to say that there were at least some merits to the various positions and philosophies of the various parties, yet no single answer could definitively be viewed as correct. In this regard, during the 2009 general rate case, Company witness Janet Phelps developed what can be characterized as a "compromise" allocation methodology that considered the merits of the various positions and attempted to develop a new allocation method wherein Ms. Phelps new methodology was: (1) consistent with cost of service principles; (2) acknowledged past Commission decisions; (3) was consistent with PSE's distribution system; (4) was fair and reasonable; and, (5) perhaps most importantly, addressed concerns raised by parties on both ends of the cost allocation spectrum.

The resulting methodology introduced by Ms. Phelps on behalf of PSE in the 2009 rate case, is the method that has continued to this day, and that which is used by Mr. Piliaris in this case.

Q: What is your overall assessment of the mains allocation method utilized by Mr. Piliaris in this case?

A: While the current method relies on several subjective decisions, this is true for many aspects of embedded cost studies in which joint cost responsibility must be assigned individual classes of customers. While I do not agree with many aspects of the PSE methodology, and I am reluctant to fully endorse the Company's approach to assign mains cost responsibility, I can inform the Commission that PSE's study is not inherently biased against any customer class.

Q: What parity ratios are produced under Mr. Piliaris' supplemental CCOSS?

A: Mr. Piliaris' supplemental CCOSS generates the following class parity ratios:

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Table 12
PSE-Natural Gas Parity Ratios
(PSE & CCOSS)

Class	Parity Ratio
Residential (Schedules 16/23/53)	108%
Comm. and Ind. (Schedules 31, 31T)	79%
Large Volume (Schedules 41, 41T)	101%
Interruptible (Schedules 85, 85T)	97%
Limited Interruptible (Schedules 86, 86T)	121%
Non-Exclusive Interruptible (Schedules 87, 87T)	76%
Special Contracts	59%
Rentals	187%
Total Company	100%

B. Natural Gas Class Revenue Distribution (Class Rate Spread)

Q: How did Mr. Piliaris develop his proposed distribution of PSE's requested natural gas revenue increase to individual customer classes?

A: In his direct testimony, Mr. Piliaris indicates that he applied the system average increase to those classes with parity ratios within +/- 10 percent of 100 percent (i.e., between 90 percent and 110 percent). For those classes between 110 percent and 150 percent of parity, Mr. Piliaris increased these classes by 50 percent of the system average percentage increase (excluding gas costs). For those classes with parity ratios above 150 percent, Mr. Piliaris recommends no increase. Finally, for those classes with a parity ratio below 90 percent, Mr. Piliaris recommends an increase of 150 percent of the system average percentage increase.

Q: Please provide a summary of PSE's proposed natural gas class revenue increases.

A: The following table provides Mr. Piliaris' proposed class revenue increases at the Company's requested revenue requirement as well as the corresponding percentage increases in margin (non-gas) rates as provided in Mr. Piliaris' supplemental testimony:

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Table 13
PSE Proposed Natural Gas Increases

Class	Current Non-Gas Revenues ($000)	Increase ($000)	Percentage Increase in Margin Rates
Residential (Schedules 16/23/53)	$304,328	$14,635	4.8&
Comm. and Ind. (Schedules 31, 31T)	$88,451	$6,381	7.2%
Large Volume (Schedules 41, 41T)	$13,519	$650	4.8%
Interruptible (Schedules 85, 85T)	$13,821	$664	4.8%
Limited Interruptible (Schedules 86, 86T)	$2,178	$52	2.4%
Non-Exclusive Interruptible (Schedules 87, 87T)	$4,789	$345	7.2%
Special Contracts	$1,370	$86	6.3%
Rentals	$6,042	$0	0.0%
Total Company	$434,497	$22,814	5.2%

Q: Is Mr. Piliaris' proposed class revenue spread reasonable?

A: While it is generally my preference to assign at least some rate increase to all rate classes when there is an overall system revenue increase warranted, I find Mr. Piliaris' proposed class revenue increases acceptable. The current rate of return for the Rental class is well above the Company's requested ROR. Furthermore, this class' revenues are sufficiently small such that any increase assigned to the Rental class would not materially impact the increases of any other class. As a result, I find Mr. Piliaris' proposed class revenue spread to be reasonable.

C. Natural Gas Residential Rate Design

Q: Please describe PSE's current and proposed Residential natural gas rate structure.

A: Currently, PSE's Residential natural gas base rates (excluding gas cost rates) include a fixed monthly customer charge of $10.34 and a flat delivery (distribution charge) of $0.36492/therm. The Company proposes to increase the fixed monthly customer charge to $11.00 and increase the flat distribution charge to $0.37992.

Q: Have you conducted an analysis to determine if PSE's proposed Residential natural gas customer charges are reasonable?

A: Yes. Similar to the direct customer cost analysis I conducted for PSE's electric operations, I have also conducted an analysis of the Company's Residential gas customer costs that can be considered in evaluating the reasonableness of fixed monthly customer charges.

Q: Please explain your natural gas Residential customer cost analysis.

A: Exhibit No.GAW-12 presents the results of my Residential natural gas customer cost analysis.

Q: Please explain your Residential natural gas customer cost analysis.

A: The direct customer costs provided on Exhibit No. GAW-12 include those rate base and expense items required for each customer connection as well as those required to maintain a customer's account. The results of my analyses indicate a monthly customer cost of $12.17 at PSE's requested 9.8 percent return on equity and $11.83 under a 9.0 percent return on equity. In this regard, it should be noted that my calculated Residential customer costs reflect the Company's proposed depreciation rates for Services, Meters, Meter Installations, House Regulators, and House Regulators Installations. I was unable to determine the Company's current depreciation rates for these accounts; therefore, I have not made such a calculation under current depreciation rates.

Q: What are your recommendations concerning the Company's proposed Residential natural gas customer charges?

A: Considering that the Company's proposed Residential natural gas customer charge of $11.00 is below my calculated direct customer cost, and the fact that the proposed increase is within a reasonable level (6.4 percent), I accept the Company's proposed Residential natural gas customer charge of $11.00 per month.

Q. Does this complete your testimony?

A. Yes.