BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY

Respondent.

DOCKET UE-140762 ET AL.

CROSS-ANSWERING TESTIMONY OF GLENN A. WATKINS (GAW-6T)

ON BEHALF OF

PUBLIC COUNSEL

NOVEMBER 14, 2014

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I. INTRODUCTION / SUMMARY

Q: Please state your name and business address.

A: My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, Virginia 23235.

Q: Have you previously pre-filed direct testimony in this proceeding?

A: Yes. I pre-filed direct testimony on October 10, 2014, which is identified as Exhibit No. GAW-1T.

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

A: The purpose of this testimony is to respond to the recommendations of Boise White Paper's ("Boise") witness Mr. Robert Stephens on issues concerning class cost allocations, respond to the class revenue allocation (rate spread) recommendations of Staff witness Mr. Jeremy Twitchell, Walmart witness Mr. Steve Chriss, and Boise witness Mr. Stephens, and respond to the Residential rate design recommendations of Staff witness Mr. Twitchell.

II. CLASS COST OF SERVICE

Q: Which witnesses address class cost allocations, also referred to as class cost of service ("CCOSS")?

A: Witnesses Twitchell, Chriss, and Stephens address CCOSS in their direct testimonies. Mr. Twitchell accepted the Company's general approach and methodology with two minor modifications based on recommendations Staff made in PacifiCorp's last general rate case. I addressed Staff's recommended modifications in my direct testimony. Mr. Chriss states that he does not take a specific position nor does he offer alternative recommendations relating to CCOSS. Mr. Stephens has significant disagreements with the methodology and approaches used by all other witnesses in this case, particularly as it relates to the classification and allocation of production (generation) and transmission-related plant and expenses.

Q: What are Mr. Stephens' disagreements and alternative recommendations as it relates to the classification and allocation of production-related plant and expenses?

A: For at least 30 years, all accepted electric utility CCOSS in Washington have classified production-related plant as partially energy-related and partially demand-related.[1] Similarly, all electric utilities in the state have allocated the demand-related portion of production plant based on multiple hours of peak usage. Mr. Stephens recommends that the long standing practice of classifying production plant as partially energy-related and partially demand-related be abandoned and opines that production-related costs should be classified as 100% demand-related.

With regard to the allocation of demand-related costs to individual classes, Mr. Stephens disagrees with the long-standing policy and numerous findings of this Commission that for purposes of developing class demand allocators,

[1] This has been a consistent practice dating back to Cause U-81-17. Since this case in 1981, there have been numerous cases in which the Commission specifically endorsed the Peak Credit method and directed its use in CCOSS. Indeed, all three of the State's investor-owned electric utilities have consistently utilized a classification methodology in which production plant is ultimately allocated partially on energy (KWH) and partially on demand (KW). As noted in my direct testimony, and until recently, all utilities have utilized what is known as the Peak Credit methodology. In recent years, Avista Utilities and PacifiCorp have proposed what is generally known as the Peak & Average ("P&A") approach to classify production plant as partially energy-related and partially demand-related.

"averaging several days for several years is more likely to avoid wide swings from year to year due to unusual weather conditions that are unlikely to occur frequently."[2] Consistent with prior Commission directives to PacifiCorp, the Company has developed its production demand allocators based on the 100 highest winter loads and 100 highest summer loads. In contrast, Mr. Stephens recommends that class demand allocation factors be developed based only on four hourly loads. Specifically, Mr. Stephens recommends that production demand allocators be based on class contributions to the single hourly highest loads during each of the months of January, July, August, and December.

Q: Is Mr. Stephens' recommendation to classify production-related plant as 100% demand-related reflective of cost causation, and is it fair and reasonable?

A: No. In my direct testimony, I discussed at length how public utility generation facilities are planned and operated such that utilities invest in a portfolio of production assets that minimize the total cost of providing service to consumers. Because of the capacity/energy cost tradeoff inherent in generation facilities, utilities will invest in a portfolio of production assets that are comprised of: base load units which are designed to serve customers' energy needs throughout the year, that inherently require high fixed costs per KW (capacity costs) yet are exceptionally efficient and produce energy with low variable costs (energy costs); peaker units that are relatively inexpensive to install on a per KW basis (have low

[2] This finding has been made by the Commission in numerous electric and gas cases going back to at least its Order in Docket No. UG-901459, Third Supplemental Order, page 8.

fixed costs per unit of capacity), but are much less efficient and have substantially higher variable costs per unit of output such that they are only operated for a few hours each year to meet peak load responsibility; and intermediate plant that can be thought of as a bridge, or hybrid, between base load and peaker units. As such, because much of an integrated electric utility's investment in generation assets is related to base load units to meet the energy requirements of its customers throughout the year, a large percentage of fixed generation costs should reflect energy usage throughout the year, while some portion should also be based on peak demands to reflect the cost associated with plants used only to meet peak loads for a few hours of the year.

Mr. Stephens ignores this fundamental and most important reality of minimizing total cost over the course of a year and opines:

> Instead, production costs should be classified and allocated to the customer classes according to each class's demand during the peak months, when <u>all</u> of PacifiCorp's production resources are in use, and when those resources are most likely to be operating at their maximum capacities. It is PacifiCorp's system peak demands, which occur during winter and summer months, that drive the need for additional capacity. Demands during moderate-load times, whether time of day or month of year, do not cause new generating capacity to be built. Energy allocators should be used only on variable costs; i.e., those which vary with the operating output of the units, such as fuel.[3]

Mr. Stephens' rationale is contrary to the reality of how electric utilities are planned and operated. If there were no capacity/energy tradeoff in various types of generation resources, utilities would only be concerned with meeting peak load requirements. Obviously, such is not the case. Indeed, under Mr. Stephens'

[3] Exhibit No. RRS-1T, pp. 6-7, ll. 17-23, 1-2.

rationale, utilities would only plan, build, and operate "peaker units" characterized with low fixed cost capital requirements and very high variable running costs. If this were the case, PacifiCorp's total generation rate base would only be a small fraction of the investment the Company has made to minimize its total cost. In other words, its fixed costs in rate base would pale in comparison to its actual investment, yet variable costs would be exceptionally higher such that the Company's total cost of service (revenue requirement) would be significantly larger than under current conditions. Although PacifiCorp's rate base is comprised largely of base load units with high fixed costs which produce inexpensive energy throughout the year, as I discuss in additional detail below, Mr. Stephens' approach would assign the Company's total rate base investment associated with these base load units (with high fixed costs) based on class contributions to only a few hours of peak load.

In summary, while PacifiCorp could conceivably meet its peak load and annual energy requirements with a generation portfolio comprised only of peaker units and, hence, have a much lower total investment in generation resources, the cost of energy produced throughout the year would be astronomically higher than a more reasonable portfolio of production assets. Because some classes, such as Residential, contribute more to system peak hours than other classes relative to their annual energy use, Mr. Stephens' peak responsibility method results in a clear bias against low load factor customer classes, as it does not recognize the fact that most of the Company's investment in generation rate base is used to provide energy throughout the year and not just meet peak load for a few hours of the year.

Q: Have you evaluated PacifiCorp's portfolio of production assets to determine its mix of base, intermediate, and peak generation facilities?

A: Yes. The Company's Federal Energy Regulatory Commission (FERC) Form 1 provides an itemization of its generation assets that provides a wealth of information including fuel type, maximum output capacity (MW), annual energy output (MWH), fixed investment costs, and variable fuel costs.[4] With this information it can be determined how often, and to what extent, a facility is utilized, what its fixed costs per unit of capacity are, as well as its average variable cost per unit of energy output.

My Exhibit No. GAW-7 provides an itemization of PacifiCorp's generation resources as reported in its most recent FERC Form 1. As can be seen in this exhibit, PacifiCorp's generation portfolio is overwhelmingly comprised of low cost base load units, which are used to serve the energy needs of its customers throughout the entire year. Specifically, the Company's FERC Form 1 reports total generation capacity of 11,223 MW, which is comprised of 6,658 MW of coal steam generation (base load), 2,231 MW of gas combined cycle generation (intermediate load), 1,068 MW of hydro generation (base load), and 1,031 MW of wind generation (non-dispatchable/unreliable sources).

[4] I recognize that PacifiCorp's generation is segregated into two control areas and that the loads and generation assets reflect the Company's total system, rather than the Western Control Area ("WCA"). However, the WCA receives the vast majority of the Company's hydro capacity and that generation output is transferred between the two control areas based on the economic dispatch of its total portfolio of production assets (subject to transmission routing and constraints).

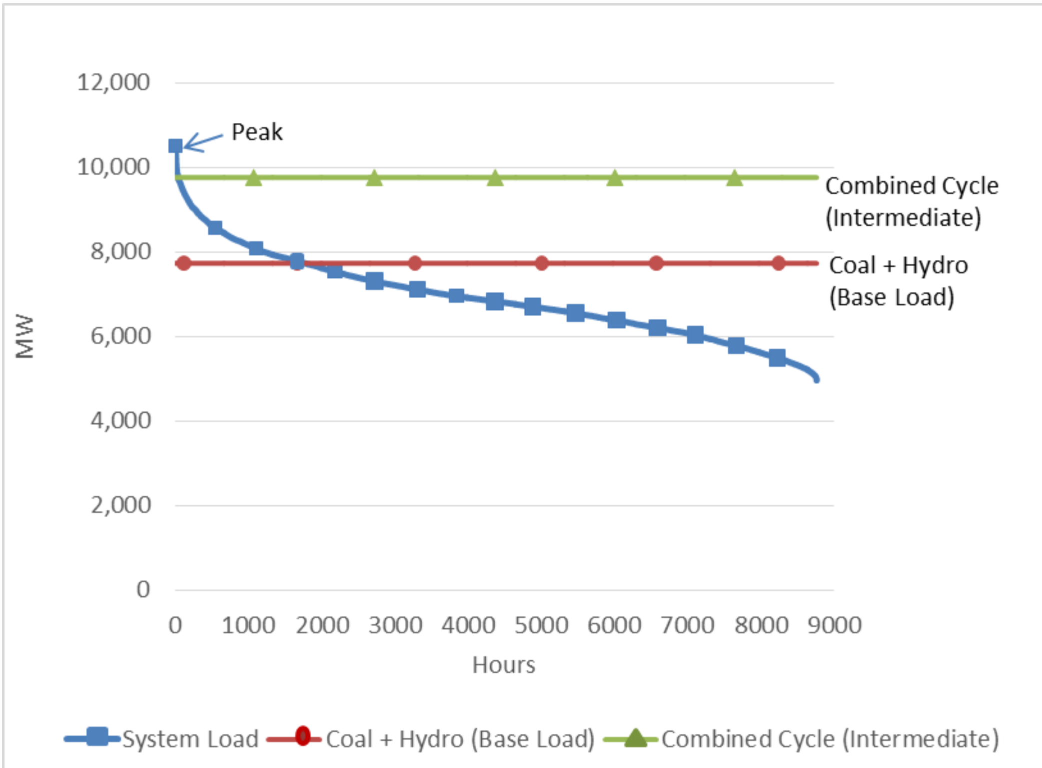
The capacity/energy tradeoff discussed above, and in my direct testimony, can be readily observed in my Exhibit No. GAW-7. The Company's base load coal units have very high capacity factors with high fixed costs per KW and correspondingly low fuel cost per KWH. The Company's natural gas combined cycle units are dispatched somewhat less than its base load units and have somewhat higher variable cost per unit than its steam units. Conversely, PacifiCorp's natural gas peaker units are only utilized for a few hours of the year (with capacity factors at or below 10%), but have exceptionally high fuel costs per unit of energy output. Furthermore, PacifiCorp is fortunate to have a large portfolio of hydro generating units with virtually no variable fuel costs.[5]

Figure 1, below, provides the Company's actual 2013 load duration curve along with the capacity provided by low variable costs, base load, hydro, and intermediate load generation.[6] As shown, the vast majority of PacifiCorp's generation assets are utilized to meet the Company's energy requirements throughout the entire year with its base load units. Furthermore, all but a few hours of PacifiCorp's hourly loads are met with its base load and intermediate units, i.e., its intermediate units are used to meet energy requirements as well. Finally, the Company's peaker units are required to only meet a few hours of peak load during the year. The utilization of PacifiCorp's generation assets and, hence, the cost causation of these assets are in stark contrast to the manner in which

[5] Hydro generation is utilized primarily to provide inexpensive energy throughout the year subject to constraints imposed by snow pack runoff, seasonal limitations for fish and wildlife and/or flood control.
[6] A load duration curve shows the total load on the system (MW) for each hour of the year sorted from highest to lowest. In this way, it is possible to determine the peaking nature of the Company's collective customers as well as the generation resources generally available to meet these hourly loads.

Mr. Stephens has allocated the Company's generation assets (plant). That is, while it is clear that the vast majority of PacifiCorp's investment in generation plant has been made to meet energy (KWH) requirements throughout the year, Mr. Stephens proposes to allocate these costs based on peak loads.

Figure 1: PacifiCorp 2013 System Load Duration and Generation Mix



Q: Is Mr. Stephens' recommendation to allocate production demand-related costs based on a single year's four highest hourly loads in January, July, August, and December reasonable?

A: No. The Commission has consistently recognized that reliance on a single year of data, coupled with only a few hourly load observations, can cause unstable results from one rate case to another and may simply be the result of anomalous weather conditions that may or may not occur during hours that are representative of customers collective load patterns. Indeed, the peak loads experienced in 2013 were considerably higher than what would be expected under normal conditions. Moreover, it should be recognized that under extreme load conditions in eastern Washington, the Company can and will purchase lower cost power from its affiliates or other utilities located further south that have excess capacity available (at a lower cost than that required to run its most inefficient peaker units).

Q: Please respond to Mr. Stephens' disagreement with how the Company has allocated transmission plant.

A: Consistent with other electric utilities in Washington, as well as prior Commission directives, PacifiCorp has allocated transmission plant on the same basis as production plant. The theory and rationale underlying this approach is that transmission lines are an extension of production facilities. That is, generation facilities are typically placed away from load centers and near the resources required to operate generation facilities. For example, hydro facilities are obviously located along rivers, while coal generation facilities are located near coal mines and/or rail facilities, and natural gas generators must be located in close proximity to natural gas pipelines. Therefore, transmission lines are simply a conduit to move the energy produced from distant generating facilities to the Company's load centers.

This Commission has recognized this reality as early as 1982 in a rate case involving Washington Water Power (predecessor to Avista) where it found:

> Classification of transmission system cost should be applied using the same principles as for production plant….The appropriate distinction between energy and capacity classification is remote production plant. Construction of baseload energy facilities at

> remote locations creates a need for transmission facilities which are energy rather than capacity cost related, and the classification should be so applied.[7]

Mr. Stephens has a different view of how transmission-related costs should be allocated across customer classes. Mr. Stephens is of the opinion that because transmission facilities have a known and measurable load capability, that customer contributions to peak load should serve as the basis for allocating these transmission costs. While there is no doubt that any given electricity conductor (i.e., a transmission line) has a physical load carrying capability, Mr. Stephens' rationale fails to recognize cost causation in three regards.

First, an allocation based simply on contributions to a few hours of peak load fails to recognize the fact that transmission facilities are indeed an extension of generation facilities and are used to move the energy produced by the generators from remote locations to where customers actually consume electricity. Second, and similar to the concept of base load units producing energy to serve customers throughout the year, Mr. Stephens' approach fails to recognize that these transmission facilities are used virtually every hour of an entire year and not just during periods of peak load. Third, any assumption that transmission costs are related to peak load implies that there is a direct and linear relationship between cost and load. In other words, one must assume that if load increases the cost of transmission facilities increases in a direct and linear manner. This is simply not the case since there are significant economies of scale associated with high voltage transmission lines.

[7] Second Supplemental Order, Cause U-82-10, p. 37.

Q: Is there additional evidence to suggest that the Company's investment in transmission facilities should recognize energy utilization throughout the year?

A: Yes. For the last several years, PacifiCorp has embarked upon a significant transmission expansion program that it refers to as its "Energy Gateway" Plan. The Company's website relating to its Energy Gateway Plan states the following benefits associated with its transmission expansion program:[8]

- Strengthens the connections between PacifiCorp's east and west control areas, providing more flexibility to move energy resources where they are needed and maintaining low-cost delivery and service reliability for customers in the six-state service area.

- Provides substantial long-term benefits to the company's service area through an electric system backbone supporting cost-efficient, flexible and diverse resource development in resource-rich areas.

- Improves access to resources through the West, helping to provide long-term rate stability and protection from future market price volatility.

- Provides essential new electric transmission infrastructure in resource-rich areas, including those areas where no new wind generation can be accommodated until transmission capacity is increased.

- Provides necessary reliability and capacity to improve the delivery of electricity throughout the region.

- New transmission is necessary for development of new energy resources of all types.

[8] Energy Gateway Fact Sheet, available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/7723-49_PC_EnergyGateway_FactSheet_v2.pdf

- Allows more efficient use of existing resources - a critical step in addressing carbon/climate change issues.

Each of these key benefits outlined by the Company relates to the energy needs of the Company's customers and not simply a requirement to meet a peak load for a few hours a year.

Q: What are your conclusions regarding Mr. Stephens' recommended changes to the methodology and approaches used to classify and allocate the Company's production and transmission-related plant?

A: This Commission has consistently rejected proposals to classify production and transmission-related plant as 100% demand-related. It has also consistently rejected proposals to allocate demand-related production and transmission-related costs based on only a few peak hours out of the year. Mr. Stephens' recommendations do not comport with cost causation, are not reflective of how the Company's utility plant is planned or operated, and result in a distinct bias against Residential and Small Commercial customers. As such, Mr. Stephens' recommendations should be rejected in their entirety.

III. CLASS REVENUE ALLOCATION (RATE SPREAD)

Q: Please identify those witnesses that offer class rate spread recommendations in this case.

A: In addition to Company witness Ms. Joelle R. Steward and I, Staff witness Twitchell, Walmart witness Chriss, and Boise witness Stephens provide class rate spread recommendations.

Q: Can you provide a comparison of the various witnesses' class rate spread

recommendations in this case?

A: Yes. However, it should be understood that Mr. Twitchell's rate spread recommendation is based on Staff's recommended increase of $7.741 million, which encompasses the Staff's required increase in base rates ($6.135 million), additional Colstrip costs ($1.880 million), reduced depreciation (-$0.836 million), and deferred costs ($0.561 million). All other witnesses' rate spread recommendations are based upon the Company's requested base rate increase of $27.2 million coupled with scale-back recommendations in the event the Commission authorizes an increase less than that requested by PacifiCorp. Because of this somewhat "apples to oranges" comparison in terms of dollar increases, it is perhaps easier to compare the various class rate spread proposals based on percentage of system average increase. The following table provides a comparison of the various witnesses' recommendations for each class increase stated in terms of percentage of overall system average increase:

Table1: Comparison of Cost of Service Proposals

		Percent of System Average Increase				
	Class	PacifiCorp	Public Counsel	Staff	Walmart	Boise Paper
16	Residential	112.2%	112.2%	150.0%	112%	112%
24	Small Gen'l Service	50.0%	50.0%	0.0%	68%	45%
36	Lg. Gen'l Service <1,000KW	112.2%	Not Addressed	70.5%	100%	112%
48T	Lg. Gen'l Service >1,000KW	112.2%	Not Addressed	99.9%	100%	112%
48T	Dedicated Facilities	112.2%	Not Addressed	150.0%	112%	112%
40	Agricultural Pumping	50.0%	Not Addressed	0.0%	68%	71%
	Street Lighting	49.6%	Not Addressed	0.0%	50%	55%
	Recreational Lighting	49.6%	Not Addressed	Included in SL	45%	--
	Partial Requirements	112.1%	Not Addressed	Excluded	113%	--
	TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%

As can be seen above, there is considerable uniformity in the recommendations of PacifiCorp, Walmart, Boise, and Public Counsel. Staff recommends a considerably larger increase to the Residential and Schedule 48T-Dedicated Facilities classes with no increases to Small General Service, Agricultural Pumping, or Street Lighting.

While Mr. Twitchell does consider gradualism in that he does not propose to move the Residential or Schedule 48T-Dedicated Facilities classes all the way to his calculated cost of service, he is of the opinion that there should be a substantially more dramatic shift towards allocated costs of service than those of all other witnesses. Similarly, because of the relatively high rates of return ("ROR") currently earned by the Small General Service, Agricultural Pumping, and Street Lighting classes, Mr. Twitchell recommends no change in rates to these customer classes. While Mr. Twitchell's rate spread recommendation can be supported by his allocation of the Company's joint costs to the various classes, it is my opinion that Mr. Twitchell has placed too much emphasis on the arithmetic of his allocated cost of service study.

To illustrate, it is my understanding that there has been a long-standing policy in Washington that if class contributions to profits are within 10% of parity, plus or minus, they are considered sufficiently close to parity, given the imprecise nature of any CCOSS. In this regard, Mr. Twitchell's own CCOSS indicates that the parity ratio at current rates for Residential is 92%, for Schedule 48T-Dedicated Facilities 93%, for Small General Service 109%, and for Agricultural Pumping and Street Lighting 107%. All are within 10% of parity, yet for some classes Mr. Twitchell recommends a substantially larger percentage increase than the system average, while for others he proposes no change in rates.

Furthermore, this Commission has opined that cost of service is but one factor to be considered in established class revenue responsibility. For example in PacifiCorp's 2010 general rate case, the Commission found as follows:

> [D]etermining an appropriate rate spread requires consideration of a number of factors and is not the result of pure arithmetic calculations. Of course we consider the results of a valid COSS with the goal of ensuring that each customer class bears the burden of the costs it imposes on the utility. However, we also consider principles of rate stability, gradualism, and the avoidance of rate shock.[9]

Although a strong argument could be made for equal percentage increases for all classes, it is my opinion that the consensus of four witnesses' recommendation for a 112% of system average percentage increase to the Residential class is reasonable and appropriate. With regard to the non-Residential classes, PacifiCorp, Walmart, and Boise's proposals are not materially different. When all factors are considered, the non-Residential rate spread recommendation of Walmart witness, Mr. Chriss is somewhat preferred. Mr. Chriss' rate spread proposal recognizes CCOSS results, as well as reasonably reflects the principle of gradualism, avoids rate shock, and, in my opinion, also recognizes the current economic climate within PacifiCorp's service area.

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[9] *Washington Util. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 315, p. 109, (March 25, 2011) (alteration in original).

IV. RESIDENTIAL CUSTOMER CHARGE

Q: What fixed monthly Residential customer charge does the Staff recommend in this case?

A: Mr. Twitchell recommends increasing the fixed Residential customer charge from $7.75 to $13.00 per month. Mr. Twitchell's proposed $5.25 increase to this charge represents a 67.7% increase.

Q: Why is Staff proposing such a large increase in the Residential fixed monthly customer charge in this case?

A: As stated on page 26 of his direct testimony, Mr. Twitchell is of the opinion that:

> [I]n the absence of a decoupling mechanism to reduce Pacific Power's risk of under-recovering fixed costs due to declining load, it is appropriate to shift the distribution of the Company's cost recovery toward fixed sources of recovery, such as the monthly basic charge. Staff's proposal of $13.00 reflects the impact of moving the Residential customer class' share of line transformer costs into the basic charge. The basic charge is intended to recover costs that do not vary based on a customer's use; that is, the costs that the Company incurs when a customer connects to the grid.[10]

Q: Before we continue, are there any factual matters in Mr. Twitchell's testimony that should be clarified or corrected?

A: Yes. On page 23 of his direct testimony, Mr. Twitchell states:

> Pacific Power is the textbook example of a utility with declining sales that has been negatively affected by obsolete rate design. Since peaking in 2005, the Company's annual load in Washington declined by an average of 0.67 percent per year through 2013.[11]

Whether misunderstood, or simply misapplied, it appears that Mr. Twitchell is confusing energy sales (MWH) with peak load (MW). PacifiCorp's Residential

[10] Exhibit No. JBT-1T, p. 26, ll. 15-22.
[11] *Id.* at p. 23, ll. 18-21.

rate structure is comprised of a fixed monthly customer charge and an inverted block energy charge. Residential customers are not billed on a demand basis. The following table reflects the Company's Washington retail energy sales (MWH) over the last five years:

Table 2: PacifiCorp Washington Retail Energy Sales (MWH)[12]

Year	MWH
2010	3,984,631
2011	4,005,863
2012	4,041,898
2013	4,023,881
2014	4,067,293

Furthermore, the Company's recently updated Integrated Resource Plan ("IRP") projects total Company Residential energy sales to increase slightly from 15,426 gigawatt hours (GWH) in 2014 to 15,709 GWH in 2019, and 16,126 GWH by 2023. At the same time, the Company's updated IRP projects decreases in the Residential peak demand in the near future.[13]

As can be seen from the data above, Mr. Twitchell's assertion that PacifiCorp's annual sales volumes have declined is simply incorrect. What is apparent is that Residential consumers are utilizing electricity more efficiently. Even though there is some growth in energy sales, peak load is projected to decline somewhat. However, this more efficient utilization of electricity does not impact the Company's revenue stream since the Residential rate structure is based on energy usage, not peak demand.

Q: Other than his desire to provide additional guaranteed revenue recovery for

[12] Per PacifiCorp Washington UTC Renewable Energy Reports, dated May 30, 2014 and June 1, 2012.
[13] PacifiCorp 2013 Integrated Resource Plan, p. 23 (Updated March 31, 2014).

PacifiCorp, does Mr. Twitchell provide any justification for his proposed increase to the Residential fixed monthly customer charge?

A: Yes. As noted earlier, Mr. Twitchell proposes to include the cost of line transformers within the recovery of fixed monthly customer charges. According to Mr. Twitchell:

> [L]ine transformers are a fixed component of the distribution system without which a Residential customer cannot receive service, and the cost of a transformer does not vary based on usage. Recovering transformer costs through the basic charge accomplishes the goal of providing the Company with more stable recovery of fixed costs while remaining aligned with cost-causation principles.[14]

While I agree with Mr. Twitchell that the cost of line transformers do not necessarily increase with customer energy usage, transformers are clearly a function of peak load (KW). Furthermore, it is well known that, in general, customers with larger KWH usage tend to also have larger KW demands. However, this is not really the most important point to consider. Any electric utility's distribution system is comprised largely of "fixed" costs including substations, poles and towers, conductors (overhead and underground), and conduit. These other major components of an electric utility's distribution system also do not vary with usage. Furthermore, while virtually every secondary voltage customer is connected to a step down line transformer, a single transformer may serve a single customer (particularly in a rural area) or may serve multiple customers (primarily in neighborhoods and urban areas). These

[14] Exhibit No. JBT-1T, pp. 26-27, ll. 22-23, 1-3 (alteration in original).

transformers are well known to be demand-related as they are sized to meet the maximum load placed upon them at any point in time from all customers served from a given transformer.

Q: Has this Commission provided guidance as to the cost causation and cost treatment of distribution line transformers?

A: Yes. In Docket UE-920433 involving Puget Sound Energy, the Company classified distribution costs using the "Basic Customer method." Under this approach, only service drops and meters are customer-related, whereas substations, poles, towers, fixtures, conduit, and transformers are demand-related. In that case, Staff strongly supported this Basic Customer method approach. However, two intervenors contended that costs other than service drops and meters should be treated as customer-related (including transformers). The Commission soundly rejected the inclusion of transformers within customer costs and stated in its Final Order:

> The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, *regardless of the presence or absence of a decoupling mechanism*. We agree with Commission Staff that proponents of the Minimum System approach have one again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.[15]

Q: So that the costing of line transformers is completely understood, how did the Company classify and allocate line transformers within its CCOSS?

[15] *Washington Util. & Transp. Comm'n v. Puget Sound Power & Light. Co*., Ninth Supplemental Order on Rate Design Issues, Docket UE-920433, p. 11 (August 17, 1993) (emphasis added).

A: Line transformers were classified and allocated as 100% demand-related.

Q: Did Mr. Twitchell accept this 100% demand-related treatment of line transformers within his CCOSS?

A: Yes. However, to provide support for his proposed Residential customer charges, Mr. Twitchell proposes to collect the cost of these transformers within fixed monthly customer charges.

Q: Do you have any concluding comments regarding Mr. Twitchell's proposal to dramatically increase the Residential customer charge?

A: Yes. In my direct testimony, I provided a detailed discussion of why high fixed monthly customer charges are at odds with accepted economic theory, the pricing practices within competitive markets, conservation and efficiency objectives, and the desires of consumers. Based on the collective wisdom of economists, regulators, and the consuming public, developed over decades, electric utility Residential pricing has been understood and structured to be based largely on volumetric usage. Furthermore, Mr. Twitchell has presented no persuasive evidence to suggest that a Residential pricing structure based largely on volumetric usage will materially hinder the Company from recovering its total cost including a fair rate of return on its investment. As such, Mr. Twitchell's recommendations should be rejected.

Q: Does this complete your testimony?

A: Yes.