

Exhibit No.\_\_\_\_(JRS-1T)  
Docket UE-14\_\_\_\_  
Witness: Joelle R. Steward

**BEFORE THE  
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,  
a division of PacifiCorp

Respondent.

Docket UE-14\_\_\_\_

**PACIFIC POWER & LIGHT COMPANY  
DIRECT TESTIMONY OF JOELLE R. STEWARD**

**May 2014**

**TABLE OF CONTENTS**

QUALIFICATIONS ..... 1  
PURPOSE OF TESTIMONY..... 1  
CLASS COST OF SERVICE STUDY..... 3  
    Description of Procedures..... 4  
RATE SPREAD..... 13  
RATE DESIGN ..... 15  
    Residential Rate Design..... 18  
    Distributed Generation..... 25  
    Low Income Customers ..... 26  
    General Service, Agricultural, and Lighting Service Rates ..... 28  
    Proposed Tariffs and New Adjustment Schedules..... 30  
NORMALIZED REVENUES ..... 31

**ATTACHED EXHIBITS**

- Exhibit No.\_\_(JRS-2)—Cost of Service by Rate Schedule – Summaries
- Exhibit No.\_\_(JRS-3)— Cost of Service by Rate Schedule – All Functions
- Exhibit No.\_\_(JRS-4)—Cost of Service Study
- Exhibit No.\_\_(JRS-5)—Proposed Allocation of Revenue Requirement Increase
- Exhibit No.\_\_(JRS-6)—Proposed Pricing and Billing Determinants
- Exhibit No.\_\_(JRS-7)—Residential Service Monthly Billing Comparisons
- Exhibit No.\_\_(JRS-8)—Residential Basic Charge
- Exhibit No.\_\_(JRS-9)—Monthly Impact of Residential Basic Charge
- Exhibit No.\_\_(JRS-10)—Comparison of Residential Rate Design
- Exhibit No.\_\_(JRS-11)—Low Income Bill Assistance Program Adjustments
- Exhibit No.\_\_(JRS-12)—Revised Tariff Pages

1 **Q. Please state your name, business address, and present position with Pacific**  
2 **Power & Light Company (Pacific Power or Company), a division of PacifiCorp.**

3 A. My name is Joelle R. Steward. My business address is 825 NE Multnomah Street,  
4 Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing, Cost of  
5 Service, and Regulatory Operations.

### 6 **QUALIFICATIONS**

7 **Q. Please describe your education and professional experience.**

8 A. I have a Bachelor of Arts degree in Political Science from the University of Oregon  
9 and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy  
10 at the University of Minnesota. Between 1999 and March 2007, I was employed as a  
11 Regulatory Analyst with the Washington Utilities and Transportation Commission.  
12 I joined the Company in March 2007 as Regulatory Manager, responsible for all  
13 regulatory filings and proceedings in Oregon. I assumed my current position in  
14 February 2012. I currently direct the work of the cost of service, pricing, and  
15 regulatory operations groups.

### 16 **PURPOSE OF TESTIMONY**

17 **Q. What is the purpose of your testimony?**

18 A. The purpose of my testimony is to present the Company's functionalized class cost of  
19 service study, the Company's proposed revenue allocation of the requested revenue  
20 increase, and the Company's proposed rates.

21 **Q. How is your testimony organized?**

22 A. My testimony is organized as follows:

- 1 • First, I present the results of the cost of service study, including a description of
- 2 the procedures used in the preparation of the study.
- 3 • Second, I present the Company's proposed rate spread, which is the allocation of
- 4 the rate increase to the customer rate schedules.
- 5 • Third, I describe and present the Company's proposal to unbundle rates and the
- 6 specific proposed rate changes for the customer rate schedules.
- 7 • Fourth, I introduce the proposed revisions to the tariffs, including two new
- 8 adjustment schedules.
- 9 • Lastly, I explain the Company's calculation of normalized present revenues,
- 10 which are used for the calculation of the revenue requirement.

11 **Q. Please summarize the Company's rate spread and pricing proposals in this case.**

12 A. The Company proposes a rate spread and rate design that is guided by the results of

13 the cost of service study. The Company is proposing to unbundle rates by service

14 function so that the costs associated with the different utility functions shown in the

15 cost of service study—generation, transmission, and distribution—are more readily

16 transparent in rates. For residential customers, the Company proposes to increase the

17 residential basic charge from \$7.75 to \$14.00 per month, with an exception for

18 customers on Schedule 17, the Low Income Bill Assistance program (LIBA). For

19 LIBA participants, the Company proposes only a \$1.00 increase in the basic charge

20 from \$7.75 to \$8.75 per month. This will provide a new year-round benefit for low

21 income customers in addition to an increase of approximately 24 percent in funding

22 for LIBA. For general service schedules, where consistent with the results from the

1 cost of service study, the Company is proposing larger increases in basic charges,  
2 load size, and demand charges.

3 **CLASS COST OF SERVICE STUDY**

4 **Q. What are the results from the class cost of service study?**

5 A. Exhibit No.\_\_(JRS-2) shows the results from the embedded class cost of service  
6 study. The study is based on the Company's annual results of operations for  
7 Washington presented in the direct testimony and exhibits of Ms. Natasha C. Siores.  
8 Exhibit No.\_\_(JRS-2) summarizes, both by customer group and function, the results  
9 of the study for the 12 months ended December 31, 2013. Page 1 shows the results at  
10 the Company's earned rate of return for that period. Page 2 shows the results using  
11 the target rate of return based on the requested \$27.2 million revenue requirement  
12 increase

13 Exhibit No.\_\_(JRS-3) shows the cost of service results in more detail by  
14 class and function. Page 1 summarizes the total cost of service by class, pages 2  
15 through 6 contain summaries by class for each major function, and pages 7 through 9  
16 contain a summary by class and major function on a unit cost basis.

17 **Q. Is the cost of service study filed in this case consistent with the methodology used**  
18 **in the Company's 2013 Washington general rate case, Docket UE-130043 (2013**  
19 **Rate Case)?**

20 A. Yes. The cost of service study filed in this case continues to employ the same  
21 methodology that was filed in the 2013 Rate Case.

1 **Q. Has the Company considered any proposed changes to the study since the 2013**  
2 **Rate Case?**

3 A. Yes. In the Partial Settlement Regarding Cost of Service, Rate Spread, and Rate  
4 Design (Partial Settlement) in the 2013 Rate Case,<sup>1</sup> the Company agreed to address in  
5 its next general rate case three proposed changes to the cost of service study  
6 recommended by Staff.<sup>2</sup> These three recommendations addressed:

- 7 • The peak credit methodology used to weight generation- and transmission-related
- 8 allocation factors.
- 9 • The allocation of wind plant, related expenses, and wind power contracts.
- 10 • The allocation of corporate account managers.

11 I address each of the items later in my testimony.

## 12 **Description of Procedures**

13 **Q. Please explain how the cost of service study was developed.**

14 A. The study employs a three-step process generally referred to as functionalization,  
15 classification, and allocation. These three steps recognize the way a utility provides  
16 electric service and assigns cost responsibility to the customer groups for whom those  
17 costs are incurred. A detailed description of the Company's functionalization,  
18 classification, and allocation procedures and the supporting calculations for allocation  
19 factors are contained in Exhibit No.\_\_\_\_(JRS-4), Tab 1.

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<sup>1</sup> *Wash. Utils. and Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-130043, Partial Settlement Regarding Cost of Service, Rate Spread, and Rate Design (Aug. 21, 2013).

<sup>2</sup> Docket UE-130043, Testimony of Christopher T. Mickelson, Exhibit No.\_\_\_\_(CTM-1T) at 4:11-22 (June 21, 2013).

1 **Q. Please describe functionalization and how it is used in the cost of service study.**

2 A. Functionalization is the process of separating expenses and rate base items according  
3 to five utility functions—production (or generation), transmission, distribution, retail,  
4 and miscellaneous.

5 • The production function consists of the costs associated with power generation,  
6 including coal mining, and wholesale purchases.

7 • The transmission function includes the costs associated with the high voltage  
8 system used for the bulk transmission of power from the generation source and  
9 interconnected utilities to the load centers.

10 • The distribution function includes the costs associated with all the facilities that  
11 are necessary to connect individual customers to the transmission system. This  
12 includes distribution substations, poles and wires, line transformers, service drops,  
13 and meters.

14 • The retail services function includes the costs of meter reading, billing,  
15 collections, and customer service.

16 • The miscellaneous function includes costs associated with regulatory expenses  
17 and other miscellaneous expenses.

18 **Q. Describe how the classification process is used in the cost of service study.**

19 A. Classification identifies the component of utility service being provided. The  
20 Company provides and customers purchase service that includes at least three  
21 different cost components: demand related, energy related, and customer related.

22 Demand-related costs are incurred by the Company to meet the maximum demand  
23 imposed on generating units, transmission lines, and distribution facilities. Energy-

1 related costs vary with the output of a kilowatt hour (kWh) of electricity. Customer-  
2 related costs are driven by the number of customers served.

3 **Q. Please describe how the Company determines cost responsibility among**  
4 **customer classes.**

5 A. After costs have been functionalized and classified, the next step is to allocate them  
6 among the customer classes. This is achieved by the use of allocation factors that  
7 specify each class's share of a particular cost driver, such as west control area peak  
8 demand, Washington distribution system peak demand, energy consumed, or number  
9 of customers. The appropriate allocation factor is then applied to the respective cost  
10 element to determine each class's share of the costs.

11 **Q. How are generation and transmission costs classified between demand and**  
12 **energy?**

13 A. The Company's generation- and transmission-related resources must provide the  
14 capacity to meet peak load (demand) and the energy needs of its customers  
15 throughout the year. In this case, the Company continues to use the same calculation  
16 as it used in the 2013 Rate Case, which uses the west control area system diversified  
17 load factor (SDLF) to determine the proportion of generation and transmission costs  
18 that are demand related. In this proceeding, the calculation results in 43 percent of  
19 generation and transmission costs classified as demand related and the remaining  
20 57 percent of costs classified as energy related.

21 **Q. How are generation and transmission costs allocated?**

22 A. Consistent with the Commission's accepted practice in Washington, the demand-  
23 related portion continues to be allocated using class loads coincident with the



1 Company's highest 100 summer (April-October) and highest 100 winter (November-  
2 March) hourly retail peak loads in the west control area. The energy-related portion  
3 is allocated using class annual megawatt hours (MWh) adjusted for losses.

4 **Q. How are distribution costs classified and allocated?**

5 A. Distribution costs are classified as either demand related or customer related. In this  
6 study, only meters and services are considered customer related, with all other costs  
7 considered demand related. Distribution substations and primary lines are allocated  
8 using the maximum rate schedule peaks. Distribution line transformers are allocated  
9 using the weighted non-coincident peak (NCP) method. The costs of secondary lines  
10 are also allocated using the weighted NCP method, but are only allocated to  
11 residential and small general service customers where line transformers are jointly  
12 used by more than one customer. Services costs are allocated to secondary voltage  
13 delivery customers only. The allocation factor is developed using the installed cost of  
14 new services for different types of customers. Meter costs are allocated to all  
15 customers. The meter allocation factor is developed using the installed costs of new  
16 metering equipment for different types of customers.

17 **Q. Please explain how customer accounting and customer service expenses are**  
18 **allocated.**

19 A. Customer accounting expenses are allocated to classes using weighted customer  
20 factors. The weightings reflect the resources required to perform activities such as  
21 meter reading, billing, and collections for different types of customers. Other  
22 customer service expenses are allocated based on the number of customers in each  
23 class.

1 **Q. How does the Company allocate administrative and general expenses, general**  
2 **plant, and intangible plant?**

3 A. Most general plant, intangible plant, and administrative and general expenses are  
4 functionalized and allocated to classes based on generation, transmission, and  
5 distribution plant. Costs identified as supporting customer systems are considered  
6 part of the retail services function and have been allocated using customer factors.  
7 Coal mine plant is allocated consistent with generation and transmission resources.

8 **Q. How are other revenues treated in the cost of service study?**

9 A. Other electric revenues are treated as revenue credits. Revenue credits reduce the  
10 revenue requirement that is to be collected from retail customers.

11 **Q. Does the cost of service study include results for partial requirements service on**  
12 **Schedule 47T (customers 1,000 kW and over)?**

13 A. No. Customers on Schedule 47T are not included in the embedded cost of service  
14 study because large commercial or industrial partial requirements customers typically  
15 have very sporadic loads that vary from day to day and from year to year, producing  
16 volatile cost of service results depending on whether or not service has been required  
17 during actual west control area peak hours. The Company's practice is to derive  
18 prices for this service from rates for full requirements service. Revenue from  
19 customers on Schedule 47T is allocated back to other classes as a revenue credit.

20 **Analysis of Staff's Recommendations from the 2013 Rate Case**

21 **Q. Please summarize Staff's first recommendation noted in the Partial Settlement.**

22 A. Staff recommended that the calculation used to classify the demand- and energy-  
23 related portions of generation and transmission costs should be revised based on the

1 top 200 hours, specifically, the highest 100 winter and 100 summer demand hours  
2 instead of a single system peak. Staff argued that this is consistent with Commission  
3 precedent and cites a prior Commission order stating that “it is preferable to use data  
4 from a longer period of time, to remove variations due to unusual weather and to  
5 achieve greater stability.”<sup>3</sup>

6 **Q. Has the Company adopted the proposed recommendation to use 200 peaks (100**  
7 **summer and 100 winter peaks) to determine demand- and energy-related costs**  
8 **for generation and transmission?**

9 A. No. The recommendation confuses the fundamental concept of allocating costs  
10 across customer classes with the classification of costs as demand and energy. The  
11 cited Commission order refers to the allocation of costs across classes, not the  
12 classification of costs as demand and energy.

13 As described earlier in my testimony, generation- and transmission-related  
14 plant is designed for and used to meet the system peak (demand) as well as serve the  
15 energy needs of its customers. Using the top 200 hours to determine what proportion  
16 of generation and transmission costs are demand related is inappropriate because 200  
17 hours flattens and averages the results and diminishes the disproportionate peak  
18 impacts from rate schedule classes with high peak and low energy needs (low load  
19 factor customers), and is not representative of the system requirements necessary to  
20 meet peak demand. Therefore, it inadequately captures the demand requirements for  
21 the system. In contrast, using 200 hours accomplishes the Commission’s intention of

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<sup>3</sup> Docket UE-130043, Exhibit No.\_\_(CTM-1T) at 15:12-13, quoting *Wash. Utils. and Transp. Comm’n v. Wash. Natural Gas Co.*, Dockets UG-940034 and UG-940814, Supp. Order 05 at 9 (Apr. 11, 1995).

1 removing variations due to weather for the allocation of costs across customer  
2 classes.

3 Further, the use of a single peak or load factor methodology was accepted in  
4 Avista’s 2012 general rate case, Docket UE-120436, where Staff referred to the single  
5 peak methodology by stating “the Company’s current method is a less complex way  
6 to determine a fair and reasonable allocation of costs, by applying a single peak credit  
7 ratio uniformly to all production and transmission costs based off a system load factor  
8 to determine the proportion of the functions that are demand-related.”<sup>4</sup> Subsequently,  
9 Staff recommended that the Commission accept the single peak or load factor  
10 methodology.

11 **Q. Please summarize Staff’s second recommendation.**

12 A. Staff proposed a new allocation factor to be applied to apportion costs specifically  
13 related to solar and wind resources (an NDG factor for non-dispatchable generation).<sup>5</sup>  
14 Staff recommended that the demand-related portion of this factor be determined by a  
15 capacity credit developed in the Company’s integrated resource plan (IRP).<sup>6</sup> This  
16 results in 4.2 percent of these costs classified as demand and 95.8 percent energy,  
17 based on the most recently acknowledged IRP. Staff’s testimony stated:

18 [T]he NDG allocation factor should be changed due to the non-  
19 dispatchable nature of wind and solar. While it is true that every  
20 source of generation has a different ability to meet peak, wind and  
21 solar have a reduced ability to meet peak demand. Generation is only

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<sup>4</sup> *Wash. Utils. and Transp. Comm’n v. Avista Corp., d/b/a Avista Utilities*, Docket UE-120436, Direct Testimony of Christopher T. Mickelson, Exhibit No. \_\_\_(CTM-1T) at 9:15-18 (Sept. 19, 2012).

<sup>5</sup> Specifically, Staff recommended this factor to be applied in place of inter-jurisdictional allocation factors S, SG, and CAGW. However, these inter-jurisdictional allocation factors are only applied in the jurisdictional allocation model (JAM), not the cost of service study.

<sup>6</sup> *PacifiCorp’s 2013 Integrated Resource Plan*, Docket UE-120416, PacifiCorp’s 2013 Integrated Resource Plan, Volume 1 at 93-94 (Apr. 30, 2013).

1 available when the wind blows at particular velocity range or when the  
2 sun shines.<sup>7</sup>  
3

4 **Q. Please explain why the Company did not adopt this proposed methodology for**  
5 **non-dispatchable generation in the cost study at this time.**

6 A. The fleet of generation resources is comprised of multiple types—baseload,  
7 intermediate, non-dispatchable—and the proposed classification recognizes the  
8 combined nature of these resources that are designed to meet peak load and supply  
9 the energy needs of its customers. Individual resources are not currently singled out  
10 in this calculation. Treating non-dispatchable generation differently would require  
11 the classification of all generation and transmission resources to be reassessed in both  
12 the West Control Area inter-jurisdictional and cost of service methodologies.

13 For purposes of this case, however, the Company conducted an analysis that  
14 applies a different cost of service allocation factor to non-dispatchable generation.  
15 This factor (F11) was calculated with a demand/energy classification of 4.2 percent  
16 and 95.8 percent, respectively, as recommended by Staff. Table 1 illustrates that  
17 including this change results in only small changes in the cost of service results. This  
18 change would not alter the Company’s proposed revenue allocation and rate design,  
19 which are discussed later in my testimony.

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<sup>7</sup> Docket UE-130043, Exhibit No.\_\_(CTM-1T) at 20:15-19.

Table 1

Description	Proposed Cost of Service	Cost of Service w/ NDG Allocator	% Change
Residential	\$ 161,763,485	\$ 160,953,189	-0.50%
Small General Service	\$ 47,098,250	\$ 47,133,170	0.07%
Large General Service <1,000 kW	\$ 69,207,394	\$ 69,425,778	0.32%
Large General Service >1,000 kW	\$ 27,595,284	\$ 27,795,848	0.73%
Dedicated Facilities	\$ 28,027,123	\$ 28,321,225	1.05%
Agricultural Pumping Service	\$ 12,558,974	\$ 12,601,490	0.34%
Street Lighting	\$ 1,612,768	\$ 1,632,578	1.23%
Total Washington Jurisdiction	\$ 347,863,278	\$ 347,863,278	0.00%

1 **Q. Please summarize Staff’s third recommendation.**

2 A. Staff proposed that expenses related to corporate account managers be directly  
3 assigned to Schedule 48T. Staff states that since corporate account managers are  
4 assigned to very large customers (loads over 750 KW), it is appropriate that the  
5 related expenses be assigned to this rate schedule.<sup>8</sup> Staff also states that the costs  
6 associated with corporate account managers should not be spread among all customer  
7 classes and that the Company should create a subaccount to keep track of corporate  
8 account manager costs so they can be directly assigned to Schedule 48T customers.<sup>9</sup>

9 **Q. Why has the Company not adopted the direct assignment of corporate account  
10 manager costs in the cost of service study?**

11 A. This recommendation could be given further consideration, however, after conducting  
12 a scenario that directly assigns the costs of corporate account managers to Schedule  
13 48T, the impact on cost of service results is minimal. Table 2 shows the impact of  
14 this analysis. This change would have no effect on the Company’s proposed rate

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<sup>8</sup> *Id.* at 21.

<sup>9</sup> *Id.* at 22.

1 spread or rate design.

Table 2

Description	Proposed Cost of Service	Cost of Service w/ Direct Allocation of CAMs	% Change
Residential	\$ 161,763,485	\$ 161,616,860	-0.09%
Small General Service	\$ 47,098,250	\$ 47,071,921	-0.06%
Large General Service <1,000 kW	\$ 69,207,394	\$ 69,205,917	0.00%
Large General Service >1,000 kW	\$ 27,595,284	\$ 27,687,248	0.33%
Dedicated Facilities	\$ 28,027,123	\$ 28,121,133	0.34%
Agricultural Pumping Service	\$ 12,558,974	\$ 12,551,621	-0.06%
Street Lighting	\$ 1,612,768	\$ 1,608,577	-0.26%
Total Washington Jurisdiction	\$ 347,863,278	\$ 347,863,278	0.00%

2 The Company, however, did not adopt this recommendation because it singles  
3 out one customer service cost for one type of customer. Costs related to customer  
4 accounts and sales are allocated to all customers under the Federal Energy Regulatory  
5 Commission (FERC) Uniform System of Accounts. Isolating individual cost drivers  
6 to specific types of customers would be complex and burdensome.

7 **RATE SPREAD**

8 **Q. How is the Company proposing to allocate the revenue increase to customer  
9 classes?**

10 A. Based on the direct testimony and exhibits of Ms. Siores, the Company's requested  
11 revenue requirement increase in this case is \$27.2 million, or 8.5 percent. The  
12 Company proposes a rate spread that allocates the revenue requirement change to rate  
13 schedule classes guided by the results of the cost of service study. Specifically, the  
14 Company proposes to: (1) allocate an increase based on one-half of the overall  
15 increase—or 4.2 percent—to the schedules that the cost of service study indicates  
16 require a significantly smaller revenue increase (Schedules 24, 40, and lighting

1 schedules); (2) the remaining increase is then spread equally to the rest of the rate  
 2 schedules, which results in a 9.5 percent increase. Table 3 shows the Company's  
 3 proposed rate spread compared to the cost of service study results.

**Table 3**

A	B	C	D	E	F
Schedule No.	Description	Cost of Service Study		Proposed	
		% Change	% of COS	%	(\$000)
16	Residential	15.5%	86.6%	9.5%	13,316
24	Small General Service	-2.8%	102.9%	4.2%	2,053
36	Large General Service <1,000 kW	3.6%	96.5%	9.5%	6,350
48T	Large General Service >1,000 kW	6.0%	94.3%	9.5%	2,503
48T	Large General Service Dedicated Facilities	12.4%	89.0%	9.5%	2,371
40	Agricultural Pumping Service	-0.8%	100.9%	4.2%	537
15,52,54,57	Street Lighting	-2.1%	102.2%	4.2%	70
	Total Washington Jurisdiction	8.5%	100.0%	8.5%	27,200

4 Column C shows the percentage increase required from the cost of service study.

5 Column D shows each rate schedule's current revenues as a percentage of cost of  
 6 service. Column E shows the Company's proposed rate spread for the requested  
 7 increase. Column F shows the proposed revenue increase for each rate schedule.

8 Table 3 demonstrates that the proposed rate spread minimizes price impacts on  
 9 customers while fairly reflecting cost of service.

10 **Q. Please explain Exhibit No.\_\_(JRS-5).**

11 A. Exhibit No.\_\_(JRS-5), Table A (page 1), shows the effect of the proposed base rate  
 12 increase. In Table A, current rate schedule numbers, the number of customers during  
 13 the test year, and the MWh of energy consumption during the test year are displayed  
 14 in columns two through four. Normalized base revenues for the test period are  
 15 displayed in column five. Proposed revenues are displayed in column six. Column  
 16 seven shows the proposed change in revenues for each schedule. Column eight



1 shows the proposed percentage change. The overall proposed base rate increase of  
2 \$27.2 million is shown at the bottom of column seven.

3 Table B (page 2), shows the effect of the proposed Schedule 92, Deferral  
4 Adjustment, to recover the costs related to deferrals for an outage at Unit 4 of the  
5 Colstrip generating unit, low hydro conditions, and depreciation. These costs are  
6 described in the testimony of Ms. Siores, and I explain the proposed Schedule 92 later  
7 in my testimony.

8 Table C (page 3), shows the combined effects of the requested base revenue  
9 increase and the amortization of the deferrals in Schedule 92.

#### 10 RATE DESIGN

11 **Q. How does the Company propose to design rates to implement the proposed**  
12 **revenue increase?**

13 A. As indicated above, the Company's rate design proposals are guided by the cost of  
14 service study in order to reflect costs and to recover the proposed revenue  
15 requirement. Exhibit No.\_\_(JRS-6) contains the proposed prices and the billing  
16 determinants used in calculating proposed prices. As shown in Exhibit No.\_\_(JRS-  
17 6), the Company is presenting the rates and proposed revenues for each rate schedule  
18 broken out by function from the cost of service study, which is called unbundling.  
19 Unbundling provides for greater transparency between cost of service and rate design.

20 **Q. Please explain how the rates are unbundled.**

21 A. Unbundled rates are calculated based on the rate schedule results from the cost of  
22 service model. Rates were unbundled into three categories: Generation,  
23 Transmission, and Distribution. The Company includes the costs for the retail (i.e.,

1 customer services, billing, and meter reading) and miscellaneous functions from the  
2 cost of service study in the Distribution category. The unbundling process for rates  
3 was done essentially through three steps. First, using the summary level cost of  
4 service results shown in Exhibit No.\_\_\_\_(JRS-2), the Company calculated the  
5 percentage of cost for each function from the total costs for each rate schedule. These  
6 percentages are shown on page 11 in Exhibit No. \_\_\_\_ (JRS-6).

7 Next, the Company applied each function's percentage to the allocated total  
8 revenue for each rate schedule. For example, 60 percent of the total costs for the  
9 residential class are related to generation, therefore 60 percent of the total allocated  
10 revenue for residential customers shown on page 1 of Exhibit No.\_\_\_\_(JRS-6) is  
11 applied to generation.

12 Lastly, rates are calculated to recover the costs for each function. The type of  
13 rate component used—basic charge, demand charge, energy charge—depends on the  
14 type of functionalized cost and whether the costs are fixed or variable.

15 **Q. What type of rate component is used to recover the costs in each functional**  
16 **category?**

17 A. Generation is comprised of both fixed (capacity or demand) and variable (energy)  
18 costs. As previously discussed, the cost of service study classifies costs between  
19 demand and energy using the west control area SDLF. Accordingly, the Company  
20 proposes to recover these costs through both energy and demand rates. The variable  
21 or net power costs are recovered through energy rates for all rate schedules, which is  
22 consistent with cost causation. While cost causation principles would support  
23 recovery of generation fixed costs through demand rates, not all customers currently

1 have the metering capability for demand charges, or three-part rates (i.e., basic  
2 charges, demand charges and energy charges). For these customers, most fixed costs  
3 are currently recovered through energy rates. For the customers that currently do  
4 have three-part rates, current demand charges recover only a portion of the fixed  
5 generation costs. As discussed below, the Company is proposing larger increases to  
6 demand charges to better reflect cost causation; however, to avoid adverse impacts to  
7 low load factor customers, in this case the remainder of the allocated generation fixed  
8 costs continue to be recovered through energy charges.

9 Transmission costs are associated with the bulk transmission system that  
10 brings power from the generation source to the load centers. Transmission is also  
11 comprised of fixed cost and variable costs. It has been the Commission's accepted  
12 practice to use the same classification methodology as used for generation to  
13 determine demand- and energy-related costs in the Transmission function in the cost  
14 of service study. Therefore, the Company proposes to recover these costs through  
15 both demand and energy rates for this case in a similar manner as described above for  
16 generation costs.

17 Distribution costs (along with retail and miscellaneous) are fixed costs  
18 associated with the local facilities necessary to connect and serve individual  
19 customers. Accordingly, these costs should be recovered through the monthly basic  
20 charges and load size charges (which are based on demand measurements). For rate  
21 schedules that do not have three-part rates (where demand meters are not available for  
22 load size measurements), as described later the Company designed rates in this case  
23 to recover half of these costs through the basic charge and half through energy rates.

1 For all other schedules, the Company proposes to recover these costs through the  
2 basic charges and load size charges.

3 **Q. Is the Company proposing to reflect these unbundled rates on customers' bills?**

4 A. At this time, the Company does not propose to make design changes to customer  
5 bills. For now, the Company proposes to reflect the unbundled rates in only the tariff.  
6 The tariff also shows the combined proposed rates that will be reflected on  
7 customers' bills.

8 **Q. Has the Company included an exhibit that shows the estimated bill impacts from  
9 the proposed rates?**

10 A. Yes. Exhibit No.\_\_\_\_(JRS-7) contains monthly billing comparisons for customers  
11 with different consumption levels for each rate schedule. These comparisons reflect  
12 the combined impact of the base revenue increase and the proposed Schedule 92.

### 13 **Residential Rate Design**

14 **Q. Please describe the Company's proposed rate design for the residential rate  
15 schedules.**

16 A. For the monthly residential basic charge, the Company proposes an increase from  
17 \$7.75 to \$14.00 per month. The remainder of the allocated increase will be recovered  
18 through the energy charges. While the Company evaluated different rate designs, as  
19 discussed later, the Company proposes to retain the existing inverted energy charge  
20 rate structure at this time with the second block for usage over 600 kWh per month.  
21 As a result, larger users will pay higher energy prices under the inverted rate design  
22 while all customers will pay a fair share of the overall price change.

1 **Q. What costs should be reflected in the basic charge?**

2 A. Fixed costs (i.e., costs that do not significantly vary with usage) are appropriate costs  
3 to include in determining the level of the residential monthly customer charge.  
4 Specifically, the Company proposes that, at a minimum, the basic charge should be  
5 determined by taking into consideration the functionalized unbundled costs in the  
6 Distribution category. As shown on Exhibit No. \_\_\_\_ (JRS-8), the cost of service study  
7 supports a monthly customer charge of approximately \$28.00 for these costs. This  
8 does not include fixed costs related to transmission and generation, which would  
9 increase this amount by an additional \$47.00 per month.

10 The Distribution function includes the radial system that connects the  
11 customer to the transmission system. This includes poles and wires, line  
12 transformers, service drops and meters. The retail costs included in the Distribution  
13 category include the retail activities associated with customer service, including meter  
14 reading, customer accounting, and customer service activities.

15 While the cost of service study supports a much higher basic charge, at this  
16 time the Company proposes to collect only half of these costs in the monthly basic  
17 charge, or \$14.00. The proposed residential customer charge is supported by cost and  
18 helps reduce intra-class cross subsidies while minimizing customer bill impacts.

19 **Q. Why is it important that the basic charge recover a significant portion of the**  
20 **fixed costs of serving customers?**

21 A. In today's environment where reductions in usage are encouraged where possible, and  
22 particularly in Washington where the Energy Independence Act requires the  
23 Company to "pursue all available conservation that is cost-effective, reliable, and

1 feasible,”<sup>10</sup> it is not appropriate to achieve the recovery of fixed costs through the  
2 variable energy components of rates. Doing so creates a conflict for the utility and  
3 unclear price signals for customers.

4 For the utility, when recovery of fixed costs is predominantly through energy  
5 rates, as is the case in residential rates in Washington, the utility has an incentive to  
6 sell more kWh in order to recover its fixed costs and is more dependent on weather  
7 and changes in usage for recovery of these costs. This is particularly true when an  
8 inverted tier rate structure is in place, as in Washington.

9 While reduced electricity purchases from the Company as a result of  
10 aggressive energy efficiency efforts or customer adoption of distributed generation  
11 will directly influence the need for variable resources, such as fuel, and potentially  
12 slow the need for new infrastructure, a drop in energy usage (or billed energy usage in  
13 the case of net metering customers) results in fewer kWh over which to recover the  
14 fixed costs that have been necessarily incurred to serve customers. For example,  
15 distribution system components—poles, conductors, line transformers, service drops,  
16 and meters—are facilities required to provide a residential customer access to electric  
17 service regardless of how much energy is used. The expenses related to maintenance  
18 of these facilities are also necessary to provide reliable service for any energy user,  
19 regardless of size. Additionally, retail service costs, which include the cost of reading  
20 meters, answering customer service phone calls, sending customer statements,  
21 processing customer payments, and providing online access to customers’ accounts  
22 are clearly unrelated to usage and are a necessary part of doing business. These costs

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<sup>10</sup> RCW 19.285.040(1).

1 do not go away when billed usage levels decrease, whether the decrease is related to  
2 weather, behavioral changes, or the adoption of energy efficient technology or  
3 distributed generation.

4 If the energy component of rates continues to be used as a mechanism to  
5 recover a large share of fixed costs, as it is presently for the residential class, this will  
6 result in greater intra-class subsidies where smaller users, or net metering customers  
7 who receive a kWh credit against actual usage, fail to pay their fair share of fixed  
8 costs. As more customers install energy efficiency measures, net metering, and other  
9 types of distributed generation systems, this will lead to additional subsidies within  
10 the residential class to pay the fixed costs of the distribution system, which places an  
11 unfair burden on other customers, including low income customers. A cost-based  
12 residential basic charge will ensure that fixed costs are fairly recovered from all  
13 customers and will reduce intra-class subsidization. It will also provide an  
14 appropriate economic price signal since recovery of fixed costs in energy charges can  
15 result in customers making uneconomic decisions based upon the mistaken belief that  
16 a reduction in electricity purchases will result in a concomitant reduction in all of the  
17 Company's costs.

18 **Q. Will the proposed increase in the residential customer charge dampen**  
19 **customers' price signals for conservation?**

20 A. No. Even with the proposed increase in the residential customer charge, nearly  
21 90 percent of residential revenue will be recovered through energy rates. This  
22 compares to the cost of service that shows that 43 percent of costs are energy related.  
23 For an average customer using approximately 1,300 kWh per month, at the proposed

1 rates nearly 90 percent of the bill is related to energy charges. For a small user half  
2 the size of an average user, a significant portion—approximately 75 percent—of the  
3 bill continues to be related to energy charges; and a high user twice the size of an  
4 average user will have 95 percent of the bill related to energy charges. Therefore, all  
5 residential customers—and high use customers in particular—will continue to have a  
6 price signal to conserve or pursue energy efficient technology.

7 **Q. How will the proposed increase in the residential customer charge impact**  
8 **average customer bills on a month-to-month basis?**

9 A. The proposed increase in the customer charge has a small impact on the average bills  
10 month to month and helps moderate seasonal differences in bills. Exhibit  
11 No.\_\_(JRS-9) shows the difference between the average monthly bill based on the  
12 requested increase with residential rates designed with the current customer charge of  
13 \$7.75 compared to the increase with the proposed residential rates at the proposed  
14 \$14.00 customer charge. As this table shows, the higher customer charge produces  
15 relatively small differences in the monthly bills for average residential customers. In  
16 the month with the largest average usage (January), the monthly bill is reduced by  
17 about \$4.00 per month and is increased in the lowest usage month (June) by about  
18 \$2.40. Exhibit No.\_\_(JRS-9) also shows the monthly bill comparison for a customer  
19 with 50 percent of average monthly usage and a customer with 150 percent of average  
20 monthly usage.



1 **Q. In the Partial Settlement in the 2013 Rate Case, the Company agreed to include**  
2 **testimony that “analyzes the current residential tiered block rate design and**  
3 **possible alternatives, including changes in the number of blocks, size of blocks,**  
4 **and impacts on low-income customers”<sup>11</sup> Has the Company prepared this**  
5 **analysis?**

6 A. Yes. Exhibit No.\_\_\_\_(JRS-10) contains initial analysis with scenarios based on the  
7 requested increase that illustrate different types of residential rate designs.

8 Specifically, the exhibit shows the following five scenarios:

- 9 • Scenario 1—Three-tier structure: This rate design scenario adds a third usage  
10 block for energy in excess of 1,300 kWh per month.
- 11 • Scenario 2—First block at 800: This scenario moves the first energy block from  
12 usage to 600 kWh to usage to 800 kWh. This was Staff’s proposal in the 2013  
13 Rate Case.
- 14 • Scenario 3—Basic Charge at \$28.00: This scenario uses a basic charge of \$28.00,  
15 which is the full cost of service for Distribution costs.
- 16 • Scenario 4—Flat Energy Charge with \$28.00 Basic Charge: This scenario uses  
17 \$28.00 basic charge and a flat energy charge for all usage.
- 18 • Scenario 5—Flat Energy Charge with \$14.00 Basic Charge: This scenario uses a  
19 \$14.00 basic charge and a flat energy charge for all usage.

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<sup>11</sup> Docket UE-130043, Partial Settlement Regarding Cost of Service, Rate Spread, and Rate Design at 4.

1 **Q. Why does the Company not include a scenario with a basic charge less than**  
2 **\$14.00?**

3 A. The Company does not include a rate design scenario for a basic charge less than  
4 \$14.00 because an increase in the basic charge is necessary in order to better reflect  
5 cost causation and minimize cost shifting, as discussed earlier.

6 **Q. Please explain why the Company proposes to retain the current rate design for**  
7 **energy charges rather than proposing a revised rate design for energy charges at**  
8 **this time.**

9 A. Without the results from the new residential consumption survey that the Company is  
10 conducting as agreed to the Partial Settlement in the 2013 Rate Case, the Company  
11 does not see a compelling reason to endorse another rate design for this proceeding at  
12 this time. The Company is concerned about the impact on customers in the LIBA  
13 program, Schedule 17, with any major change in rate design. The program is  
14 designed to reflect the current two-tier energy charge rate design with an energy  
15 credit for usage over 600 kWh. Any changes in the block level may significantly  
16 alter the LIBA benefits to current participants without a major redesign of that  
17 program.

18 Additionally, the Company does not support adding a third block for higher  
19 usage for several reasons. First, the Company's current rate design already reflects a  
20 steeply inverted block rate that sends a strong price signal. Second, an upper tier may  
21 increase revenue volatility as it would be more subject to changes in temperature and  
22 economic activity, particularly when a significant portion of fixed costs are recovered  
23 through energy rates. Third, there is no cost basis to support a higher block energy

1 rate, and in fact, as I will discuss later, sends the wrong economic signal for  
2 distributed generation that will increase cost shifting to other customers.

3 **Q. What is the status of the Company's Washington residential survey for end-use**  
4 **consumption and rate design that the Company committed to conduct in the**  
5 **Partial Settlement in the 2013 Rate Case?**

6 A. The Company has been working with a vendor to prepare and conduct the survey.  
7 The survey questionnaire will be sent to current customers both through U.S. mail  
8 and electronic mail by mid-May 2014. Responses are due in early June. The draft  
9 questionnaire includes approximately 57 questions related to end uses, understanding  
10 of current rate design, and household characteristics such as age and income. After  
11 receiving the data, the Company will provide a copy of the survey results to parties by  
12 July 31, 2014, as required by the Partial Settlement.

13 **Distributed Generation**

14 **Q. Is the Company making any specific recommendations related to net metering**  
15 **customers in this proceeding?**

16 A. No. The Company is preparing a new load research study that will allow us to better  
17 determine and reflect the unique costs of providing service to net metering and  
18 distributed generation customers (collectively, DG customers). Customers with  
19 distributed generation obtain a portion of their total electricity consumption from their  
20 own generation, and therefore have a distinctly different load shape and load factor  
21 when compared to the average residential customer for whom the traditional two-part  
22 rates (basic charge and energy charges) are designed. The load research study will

1 provide detailed usage patterns to facilitate the Company's development of a new rate  
2 schedule and new rate design for DG customers in its next general rate case.

3 The Company believes that distributed generation can be beneficial to the grid  
4 and the customers served from that grid, but realizing that benefit requires integration  
5 of the customer generation into the grid. Rates should provide DG customers with  
6 incentives to: (1) avoid rapidly ramping up electricity purchases as distributed  
7 generation production wanes or is unavailable; and (2) reduce electricity purchases at  
8 peak times. To do this, the Company expects to propose a three-part rate design with  
9 a demand rate component, similar to that already widely used for general service  
10 schedules. The adoption of a demand rate for on-peak usage will not only more  
11 accurately reflect the system requirements of these customers at the time of peak but  
12 also provide a more accurate price signal compared to current residential rates in  
13 which all demand-related costs are recovered through energy charges.

14 **Low Income Customers**

15 **Q. Does the Company have a proposal to address low income customers in this**  
16 **filing?**

17 A. Yes. The Company is proposing to increase the basic charge only \$1.00 for a basic  
18 charge of \$8.75 for customers on Schedule 17, the LIBA program. This will provide  
19 a year-round benefit to customers in the LIBA program and save LIBA customers  
20 approximately \$63.00 per year in additional bill savings.

21 Additionally, the Company has reflected changes to the LIBA program  
22 consistent with the five-year plan set forth in the stipulation in Docket UE-111190

1 and approved by Order 07.<sup>12</sup> The provisions of the five-year plan for 2012 through  
2 2016 are summarized as follows:

- 3 • Beginning in 2012, 10 percent of clients will be certified as eligible for a two-year  
4 period with the percent certified rising to 25 percent of clients in 2015. For the  
5 2015-2016 program year (November 2015–April 2016), there will be 5,664  
6 participants certified; 944 of which will be certified for two years.<sup>13</sup>
- 7 • Agency funding for certifying each client was set at \$65.00 for the 2012-2013  
8 program year as of June 1, 2012. Agency funding will increase each May 1 by  
9 \$2.50 through 2016 to \$75.00 per certification. So for the 2015-2016 program  
10 year, funding will be \$72.50 per certification with a maximum of 4720  
11 certifications per year.<sup>14</sup>
- 12 • Benefits to each participating customer will be increased two times the percentage  
13 increase of any future residential general rate increase between 2013 and 2016.
- 14 • The Company will file for an increase annually, around May 1, for the Schedule  
15 91 surcharge, which funds the LIBA program, to reflect increased funding  
16 requirements. The Schedule 91 surcharge increases will be applied on an equal  
17 percentage basis to all rate schedules.

18 **Q. What is the proposed increase in Energy Rate Credits for LIBA participants in**  
19 **this filing?**

20 A. As required by the stipulation, the Company has applied an increase to Schedule 17  
21 credits that is two times the average residential customer increase, the result of which

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<sup>12</sup> *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-111190, Order 07, ¶ 17 (Mar. 30, 2012).

<sup>13</sup> See Docket UE-111190, Testimony of Deborah J. Reynolds, Exhibit No.\_\_\_\_(DJR-3) at 1, (Jan. 6, 2012).

<sup>14</sup> *Id.*

1 is a proposed 24 percent increase to the average LIBA participant benefit. The  
2 proposed Energy Rate Credits are shown on page 2 in Exhibit No.\_\_\_\_(JRS-11).

3 **Q. Has the Company included an increase in this filing to Schedule 91, Low Income**  
4 **Bill Assistance Program surcharge, which funds LIBA?**

5 A. No. Based on the five-year plan, the Company is to file changes to the Schedule 91  
6 monthly surcharge around May 1 each year to reflect the increased funding  
7 requirements associated with the five-year plan or possibly in the compliance filing  
8 following a general rate case order. Schedule 91 was included in the compliance  
9 filing for the 2013 Rate Case to reflect the increased customer benefits approved in  
10 that case. Following a final order in this rate case, the Company proposes to again  
11 file changes to Schedule 91 as part of the compliance filing to recover the increase in  
12 the participant benefits and any other necessary changes.

13 For informational purposes, page one of Exhibit No.\_\_\_\_(JRS-11) shows the  
14 proposed increase in Schedule 91 funding as a result of the proposed impact of this  
15 general rate case. As this exhibit shows, the proposed collections for Schedule 91  
16 would increase 21 percent from \$2.0 million to \$2.4 million per year. Schedule 91  
17 does not include the impact from the Company's proposal for a lower customer  
18 charge to apply to LIBA customers. This benefit is recovered through the residential  
19 rates.

20 **General Service, Agricultural, and Lighting Service Rates**

21 **Q. What changes are proposed for General Service Schedules 24?**

22 A. For General Service Schedule 24, the Company proposes to increase the basic charge  
23 to \$10 per month, along with an increase to the load size charge. These increases will

1 result in approximately one-half of the costs related to Distribution to be recovered  
2 through the basic charges, which is consistent with the Company's proposal for  
3 residential customers. The remainder of Distribution costs will be recovered through  
4 the demand and energy charges.

5 **Q. What changes are proposed for General Service Schedule 36?**

6 A. For General Service Schedules 36, the Company has applied the class average  
7 increase to the load size charge and a larger increase to the demand charges in order  
8 to move these cost components closer to cost of service. The Company is proposing  
9 no change to the customer charge. Other charges in Schedule 36 have been increased  
10 on a uniform basis to recover the balance of the allocated increase.

11 **Q. What changes are proposed for General Service Schedule 48T?**

12 A. For General Service Schedule 48T, the Company has also applied the class average  
13 increase to the load size charge and a larger increase to the demand charges in order  
14 to move these cost components closer to cost of service. The Company is proposing  
15 no change to the customer charge. Other charges have been increased on a uniform  
16 basis to recover the balance of the allocated increase.

17 For General Service Schedule 48T Dedicated Facilities, the Company is  
18 proposing increases to the customer and load size charges and a larger increase to the  
19 demand charge, consistent with the cost of service study. The remaining allocated  
20 revenue is applied to the energy charges.

21 **Q. What changes are proposed for Agricultural Pumping Schedule 40?**

22 A. The Company proposes to apply a uniform percentage increase to all billing elements.

1 **Q. What changes are proposed for lighting schedules?**

2 A. The Company proposes to apply the increase to all billing elements on a uniform  
3 basis.

4 **Proposed Tariffs and New Adjustment Schedules**

5 **Q. Have you included the Company's proposed revised Washington electric tariff**  
6 **schedules in this filing?**

7 A. Yes. Exhibit No.\_\_\_\_(JRS-12) contains revised tariff sheets incorporating the changes  
8 proposed for approval in this proceeding. The revised tariff sheets reflect unbundled  
9 rates as explained earlier in my testimony. The Company has also included a new  
10 tariff sheet, Schedule 80, Summary of Effective Rate Adjustments. For increased  
11 transparency and administrative ease, Schedule 80 identifies the adjustment schedules  
12 applicable to each electric service rate schedule.

13 In addition to the rates schedules discussed in my testimony, Exhibit  
14 No.\_\_\_\_(JRS-12) contains the following:

- 15 • The proposed revisions to Schedule 300 and various Rule tariff pages that are  
16 discussed in the direct testimony of Ms. Barbara A. Coughlin.
- 17 • Proposed Schedule 94 to implement any future rate adjustments for the  
18 Renewable Resource Tracker Mechanism (RRTM) discussed in the direct  
19 testimony of Mr. Gregory N. Duvall.



- 1 • Proposed Schedule 92, Deferral Adjustments, to amortize the deferrals related to  
2 Colstrip, hydro, and depreciation that are discussed in the direct testimony of Ms.  
3 Siores.<sup>15</sup>

4 **Q. How does the Company propose to allocate any future rate adjustments related**  
5 **to the RRTM in Schedule 94?**

6 A. For recovery of these costs, the Company proposes to allocate the deferral amount in  
7 the annual filing to rate schedules based on an allocation of generation costs from the  
8 cost of service study in the most recently completed general rate case. The Company  
9 proposes setting rates for any credits or surcharges on this schedule on a cents per  
10 kWh basis for each rate schedule.

11 **Q. Please explain how the Company is proposing to recover the deferral amounts**  
12 **related to Colstrip, hydro, and depreciation in Schedule 92.**

13 A. For recovery of these costs, the Company proposes to allocate the combined deferred  
14 amounts identified in Ms. Siores's direct testimony to rate schedules based on overall  
15 proposed revenues for each rate schedule. The rates are designed on a cents per kWh  
16 basis. The proposed rates are shown on Table B, Exhibit No.\_\_(JRS-5).

#### 17 **NORMALIZED REVENUES**

18 **Q. Please explain how the Company prepared normalized revenues for the test**  
19 **period in this case?**

20 A. Normalized revenues are the 12-month revenues for the test period with certain  
21 adjustments applied in order to establish a 12-month base period on which to

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<sup>15</sup>The Company also proposes to include in Schedule 92 the amortization for the deferral related to the Merwin Fish Collector if the Commission does not approve the Company's separate tariff rider in Advice No. 14-03 for Schedule 90, Hydro Investment Adjustment, but does approve the Company's alternative request for an accounting order.

1 determine revenue requirement. Normalized revenues are developed using the actual  
2 billing units for the 12 months in the test period. Billing units include the number of  
3 customers, demand measurements (kW), both maximum and by time period such as  
4 on-peak, where applicable, energy measurements by block (kWh), and excess kVar.  
5 The Company removes any out of period billing adjustments from historical billing  
6 units and revenues then applies temperature adjustments. Current rates are then  
7 applied to all billing units to calculate annualized revenues. Using a full 12-month  
8 period for billing units is necessary to capture seasonal variations in customers and  
9 usage and to be consistent with the cost of service study that allocates costs using the  
10 same 12-month period. This calculation is consistent with the Commission's long-  
11 established practice.

12 **Q. Does this conclude your direct testimony?**

13 A. Yes.