

Exhibit No.____(JRS-7T)
Docket UE-130043
Witness: Joelle R. Steward

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFICORP d/b/a
Pacific Power & Light Company

Respondent.

Docket UE-130043

PACIFICORP

REBUTTAL TESTIMONY OF JOELLE R. STEWARD

August 2, 2013

TABLE OF CONTENTS

PURPOSE AND SUMMARY 1
REBUTTAL EXHIBITS 3
COST OF SERVICE..... 3
RATE SPREAD..... 9
RESIDENTIAL RATE DESIGN 12
GENERAL SERVICE, AGRICULTURAL PUMPING AND STREET LIGHTING RATE
DESIGN 21
ADJUSTMENT TO ANNUALIZE REVENUES 22

ATTACHED EXHIBITS

- Exhibit No. ___(JRS-8)—Cost of Service by Rate Schedule—Summaries
- Exhibit No. ___(JRS-9)—Cost of Service by Rate Schedule—All Functions
- Exhibit No. ___(JRS-10)—Effect of Proposed Rate Increase
- Exhibit No. ___(JRS-11)—Proposed Prices and Billing Determinants
- Exhibit No. ___(JRS-12)—Monthly Billing Comparisons
- Exhibit No. ___(JRS-13)—Basic Charge Calculation
- Exhibit No. ___(JRS-14)—Survey of Monthly Basic Charges in Washington

1 **Q. Are you the same Joelle R. Steward that previously submitted direct testimony**
2 **on behalf of PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or**
3 **Company) in this case?**

4 A. Yes.

5 **Q. Are you adopting the direct testimony of Mr. C. Craig Paice in support of the**
6 **cost of service study?**

7 A. Yes.

8 **PURPOSE AND SUMMARY**

9 **Q. What is the purpose of your rebuttal testimony?**

10 A. The purpose of my rebuttal testimony is to present the class cost of service (COS)
11 study results, rate spread, and rate design proposals reflecting the Company's revised
12 revenue requirement. I also respond to the direct testimony of Mr. Christopher T.
13 Mickelson on behalf of the Washington Utilities and Transportation Commission
14 (Commission) Staff, Mr. Glenn A. Watkins on behalf of the Public Counsel Division
15 of the Washington Attorney General's Office (Public Counsel), and Mr. Michael C.
16 Deen on behalf of Boise White Paper, LLC (Boise), regarding their positions on COS,
17 rate spread, and rate design. Finally, I respond to the revenue normalization
18 adjustment proposed by Mr. James R. Dittmer on behalf of Public Counsel.

19 **Q. Please summarize your testimony.**

20 A. First, concerning COS results, while no party proposed changes to the COS study for
21 this proceeding, Mr. Mickelson recommends three changes for the study for the next
22 general rate case. Mr. Mickelson's first proposal—to modify the peak credit
23 calculation—is not well supported, particularly in light of the cost shifting that would

1 occur as a result of his recommendation. Mr. Mickelson's second recommendation—
2 to create a new allocation factor for non-dispatchable generation—is poorly specified,
3 and it remains uncertain what specific information he is seeking; the Company is
4 therefore unable to take a position regarding this proposal at this time. Finally, Mr.
5 Mickelson's recommendation to assign corporate account managers to Schedule 48T
6 could be given further consideration; however, the cost impacts are minimal.

7 Concerning rate spread and rate design, the Company proposes a rate spread
8 and rate design largely consistent with my direct testimony. The proposed rate spread
9 follows the same methodology the Company proposed in its direct case and is a
10 reasonable middle ground between the proposals from Mr. Mickelson and Mr. Deen.
11 It makes movement to COS for all rate schedules. The Company's proposed rates
12 have been revised to reflect the rebuttal revenue requirement presented by Mr. Steven
13 R. McDougal. The Company is proposing a residential basic charge of \$8.85, which
14 is based on the basic charge calculation proposed by Mr. Mickelson. The Company
15 does not support Mr. Mickelson's other proposed changes to residential rate design
16 because the supporting information is neither current nor necessarily reflective of the
17 Company's Washington service area. The Company's current residential rate
18 structure already sends strong price signals to more customers than Mr. Mickelson's
19 proposed rate structure, including high usage customers. In addition, the proposed
20 rate structure could adversely impact the benefits customers receive through the Low
21 Income Bill Assistance Program (LIBA).

22 Finally, concerning revenue normalization, the Company does not agree to use
23 Mr. Dittmer's proposed methodology to calculate annualized revenue.

1 **REBUTTAL EXHIBITS**

2 **Q. Have you prepared exhibits showing the Company’s revised class COS results,**
3 **rate spread, and rate design based on the revised revenue requirement proposed**
4 **by Mr. McDougal in this rebuttal filing?**

5 A. Yes. Exhibit No.__(JRS-8) contains summary tables from the Company’s COS
6 study for the state of Washington based on changes in the Washington results of
7 operations. Exhibit No.__(JRS-9) displays the COS study in more detail by class
8 and function: page 1 summarizes the total COS by class, pages 2 through 6 contain a
9 summary by class for each major function, and pages 7 through 9 contain the unit
10 costs by function and class. Exhibit No.__(JRS-10) shows the proposed rate spread
11 for the revised revenue requirement increase. Exhibit No.__(JRS-11) contains the
12 proposed prices and billing determinants used in calculating the proposed prices.
13 Exhibit No.__(JRS-12) contains monthly billing comparisons for the revised
14 proposed prices at different usage levels for each rate schedule. Exhibit No.__(JRS-
15 13) contains the calculation of the residential basic charge. Exhibit No.__(JRS-14)
16 shows the basic charges for other utilities in Washington.

17 **COST OF SERVICE**

18 **Q. Is the Company proposing changes to the COS methodology from the methods**
19 **proposed in its direct testimony?**

20 A. No. The only change reflected in the COS study is to incorporate the rebuttal results
21 of operations for Washington presented in the rebuttal testimony of Mr. McDougal.
22 No party recommended changes to the study for this case; however, Mr. Mickelson

1 recommends that three changes be incorporated in the COS study for the next general
2 rate case.

3 **Q. What does Mr. Mickelson recommend regarding the Company’s COS study for**
4 **the next general rate case?**

5 A. Mr. Mickelson recommends the following three changes:

- 6 • Modify the peak credit calculation to use 200 peak hours in order to classify
7 energy-related versus demand-related costs.
- 8 • Develop and use a new non-dispatchable generation allocation factor.
- 9 • Assign corporate account manager expenses to Schedule 48T customers.

10 **Q. Please explain Mr. Mickelson’s first recommended change to the next COS**
11 **study.**

12 A. Mr. Mickelson recommends that consistent with the testimony of Ms. Kendra A.
13 White regarding the calculation of inter-jurisdictional allocation factors, the peak
14 credit calculation used in the COS study should be revised in the next general rate
15 case based on 200 hours, specifically, the highest 100 winter and 100 summer
16 demand hours.¹ Mr. Mickelson argues that this is consistent with Commission
17 precedent and cites a prior Commission order that states “it is preferable to use data
18 from a longer period of time, to remove variations due to unusual weather and to
19 achieve greater stability.”² Mr. Mickelson also cites an order in a Puget Sound
20 Energy, Inc., (PSE) case as precedent.³

¹ Exhibit No.__(CTM-1T) at page 15.

² *Id.*, at page 15, lines 12-13, quoting *Wash. Utils. & Transp. Comm’n v. Washington Natural Gas Company*, Dockets UG-940034 and UG-940814, Supplemental Order 05 at 9 (April 11, 1995).

³ *Wash. Utils. & Transp. Comm’n v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, and UE-921262, Supplemental Order 09 at 12 (August 17, 1993).

1 In the COS study, the peak credit calculation is used to classify the
2 production– and transmission–related costs between demand and energy. In direct
3 testimony, the Company proposed a revised peak credit calculation that uses the west
4 control area system diversified load factor (SDLF) to determine the portion of
5 generation and transmission costs that are energy and demand related. Previously, the
6 Company used the capacity cost data from the Bonneville Power Administration
7 (BPA) Firm Capacity Sales Agreement to determine the demand-related classification
8 component with all remaining costs considered energy related. Since this BPA
9 agreement expired in 2011, the Company proposed the SDLF because it was
10 straightforward, based on actual loads, and produced relatively consistent demand and
11 energy relationships between test periods. It had also been adopted for the peak
12 credit calculation in the most recent Avista Corporation d/b/a Avista Utilities (Avista)
13 general rate case, Docket UE-120436.

14 The SDLF is based on the coincident peak with the resulting load factor to be
15 applied as the energy-related component of production and transmission costs. This
16 calculation produces a ratio of 38 percent demand-related costs and 62 percent
17 energy-related costs in the current proceeding. These percentages are relatively
18 consistent with the classification percentages used in the Company’s last two general
19 rate cases, Dockets UE-111190 (35 percent demand/65 percent energy) and
20 UE-100749 (33 percent demand /67 percent energy).

21 **Q. What is the Company’s perspective on Mr. Mickelson’s recommendation for the**
22 **peak credit calculation for the next general rate case?**

23 A. The Company has several concerns with Mr. Mickelson’s proposal. First, the

1 Commission orders that he cites as precedent to support using more hours specifically
2 address the allocation of costs across customer classes not the classification of costs
3 between demand and energy; therefore, the cited orders are neither relevant to the
4 issue presented here nor precedential in this case. Using the top 200 hours to
5 establish a load factor to determine what proportion of production and transmission
6 costs are energy related is different than using Mr. Mickelson's proposed top 200
7 hours to determine each rate schedule's share of energy-related costs. Using 200
8 hours to establish an overall load factor would smooth and average the results and
9 ignore the true peak impacts of different rate schedules. This will result in an
10 improper allocation of costs to each rate schedule that is not representative of each
11 rate schedule's impact on the system at the time of peak demand.

12 Using 200 hours would produce a ratio of 27 percent demand and 73 percent
13 energy—a 29 percent drop in the demand-related classification of generation and
14 transmission costs.⁴ This will have the effect of shifting costs from residential and
15 small general service rate schedules to large general service rate schedules, and
16 disproportionately to high load factor customers. In the next general rate case, these
17 changes would likely produce significant rate impacts simply due to a change in
18 methodology without any underlying change in actual costs. These results would
19 ignore the regulatory principles of cost-causation, consistency, and gradualism.

20 Additionally, Mr. Mickelson's rejection of a single peak or load factor ratio
21 methodology in this proceeding contradicts his direct testimony in Avista's 2012
22 general rate case, Docket UE-120436, where he referred to the single peak

⁴ Mr. Mickelson may not be aware of this ratio because he did not perform the calculation. See Exhibit No.__(RBD-4).

1 methodology by stating “the Company’s current method is a less complex way to
2 determine a fair and reasonable allocation of costs, by applying a single peak credit
3 ratio uniformly to all production and transmission costs based off a system load factor
4 to determine the proportion of the functions that are demand-related.”⁵ Subsequently,
5 he recommended the Commission accept the single peak or load factor methodology
6 with the following comment:

7 The refinement to the Company’s prior method is reasonable.... This
8 method should be more stable compared to the prior method, due to
9 the reduction of shifting costs back and forth between energy and
10 demand, as the cost of natural gas to fuel combustion turbines
11 changes.⁶

12 In addition to this contradictory perspective, Mr. Mickelson provides no supporting
13 analysis demonstrating rate schedule revenue requirement changes and subsequent
14 cost shifting that would occur among the various schedules if his recommendation
15 were utilized in the COS study. The rationale for this recommendation is not clear,
16 and it should be rejected.

17 **Q. How do you respond to Mr. Mickelson’s second recommendation for the next**
18 **COS study?**

19 A. The Company is uncertain about the context and application for Mr. Mickelson’s
20 recommendation to create a new allocation factor for non-dispatchable generation
21 (NDG). He states that the current allocation of non-dispatchable generation plants,
22 related expenses, and non-dispatchable generation power contracts is problematic; he
23 suggests continued use of the current Situs (S) and System Generation (SG) allocation
24 factors, but the creation of a new factor—the NDG—to be substituted anywhere the

⁵ Docket UE-120436, Direct Testimony of Christopher T. Mickelson, Exhibit No.__(CTM-1T) at page 9 (Sept. 19, 2012).

⁶ *Id.* at 10.

1 Control Area Generation West (CAGW) factor is being applied to non-dispatchable
2 generation resources.⁷ However, Mr. Mickelson’s observation that these changes
3 relate to the COS study is incorrect. Allocation factors S, SG, and CAGW are only
4 utilized for inter-jurisdictional allocations in the jurisdictional allocation model
5 (JAM) and not the COS study. While it is true that JAM results of operations flow
6 into the COS study, Mr. Mickelson’s testimony implies that JAM allocation factors
7 are somehow utilized within the COS study. JAM allocation factors are included in
8 the COS study (see “Func Study” tab) for illustrative purposes; however, they are not
9 utilized to functionalize, classify, or allocate costs among Washington rate schedules,
10 which is the purpose of the COS study. In response to a discovery request from the
11 Company, Mr. Mickelson reiterated that his testimony relates to the COS model.
12 Therefore, the Company is unable to ascertain the proper context and application for
13 this recommendation.

14 Additionally, Mr. Mickelson recommends that “the Commission require the
15 Company to provide the information necessary for Staff to review a new NDG
16 allocation factor for the apportionment of non-dispatchable generation resources,
17 related expenses, and non-dispatchable generation power contracts” in the next full
18 general rate case filing.⁸ However, Mr. Mickelson does not specify the specific
19 information requested. In discovery, Staff requested and the Company provided a
20 revised JAM and COS study that separately identified and allocated wind-related
21 costs, which is the most significant type of non-dispatchable generation in the
22 Company’s resource portfolio. The Company is uncertain what additional

⁷ Exhibit No.__(CTM-1T) at pages 17-18.

⁸ Exhibit No.__(CTM-1T) at page 17.

1 information Staff finds necessary. Until Staff more clearly specifies its
2 recommendation, the Company is unable to take a position regarding Mr.
3 Mickelson's proposal.

4 **Q. Please explain Mr. Mickelson's third recommendation for the next COS study.**

5 A. Mr. Mickelson proposes that expenses related to corporate account managers be
6 directly assigned to Schedule 48T.⁹ He states that since corporate account managers
7 are assigned to very large customers (loads over 750 KW), it is appropriate that the
8 related expenses be assigned to this rate schedule. Mr. Mickelson also states that the
9 costs associated with corporate account managers should not be spread among all
10 customer classes and that the Company should create a subaccount to keep track of
11 corporate account manager costs so they can be directly assigned to Schedule 48T
12 customers.¹⁰

13 **Q. Should Mr. Mickelson's third change be considered for use in future COS**
14 **studies?**

15 A. This recommendation could be given further consideration since corporate account
16 managers are assigned to Schedule 48T customers only. However, the cost impact
17 would be minimal.

18 **RATE SPREAD**

19 **Q. Based on the rebuttal revenue requirement filed in this case, what is the**
20 **Company's rate spread proposal?**

21 A. The Company makes no change to the proposed rate spread methodology in my direct
22 testimony, but updates the rate spread to reflect the rebuttal revenue requirement

⁹ *Id.* at 21.

¹⁰ *Id.* at 22.

1 increase of \$36.9 million. The updated proposed rate spread is shown in Exhibit
2 No.____(JRS-10). As in my direct testimony, the Company proposes to allocate: (1) a
3 below-average increase to the rate schedules that the COS study indicates require a
4 significantly smaller revenue increase (Schedules 24, 40 and lighting schedules); (2)
5 the average percentage increase to Schedules 36 and 48T (other than Schedule 48T
6 Dedicated Facilities), for which the COS study supports increases relatively close to
7 the average increase; and (3) a slightly above-average increase to residential and
8 Schedule 48T Dedicated Facilities because the COS study indicates that those rate
9 schedule classes require the largest rate increases. Table 1 shows the Company’s
10 updated proposed rate spread proposal compared to the COS results. This table is
11 presented in the same format as the Table 1 included in my direct testimony. Column
12 C shows the percentage increase required from the COS study. Column D shows
13 each rate schedule’s current revenues as a percentage of COS. Column E shows the
14 Company’s proposed rate spread for the requested increase. Column F shows each
15 rate schedule’s revenues as a percentage of COS after the increase.

TABLE 1

A	B	C	D	E	F
Schedule No.	Description	Cost of Service Study		Proposed Change	
		% Change	% of COS	% Change	% of COS
16	Residential	16.2%	96.6%	12.9%	97.2%
24	Small General Service	2.8%	109.3%	10.3%	107.3%
36	Large General Service <1,000 kW	9.5%	102.3%	12.2%	102.4%
48T	Large General Service >1,000 kW	13.7%	98.5%	12.2%	98.8%
48T	Large General Service Dedicated Facilities	18.7%	93.8%	12.9%	95.1%
40	Agricultural Pumping Service	1.7%	110.9%	10.3%	108.5%
15,52,54,57	Street Lighting	-5.2%	118.3%	3.4%	109.1%
	Total Washington Jurisdiction	12.2%	100.0%	12.1%	100.0%

1 **Q. Both Mr. Mickelson and Mr. Deen propose modifications to the Company’s rate**
 2 **spread proposal. Please respond.**

3 A. Both Mr. Mickelson and Mr. Deen propose a rate spread based on each rate
 4 schedule’s relative proportion to COS, or parity ratio.¹¹ Similar to the Company, Mr.
 5 Mickelson proposes higher increases to the schedules that are below COS and smaller
 6 increases (or no increase in the case of street lighting schedules) to the schedules
 7 above COS.¹² However, Mr. Mickelson’s proposal attempts to move all schedules to
 8 within five percent of parity,¹³ whereas the Company’s proposal made more moderate
 9 movements to COS for all rate schedules. Mr. Deen also proposes below average
 10 increases to the rate schedules that are above COS by more than 10 percent (Schedule
 11 40 and street lighting) but proposes all other schedules receive an equal percentage
 12 increase.¹⁴ Table 2 shows each party’s proposed increase by rate schedule as a
 13 percent of the overall increase.

TABLE 2

Proposed Increase as a Percent of Overall Increase				
A	B	C	D	E
Schedule No.	Description	Company	Boise	Staff
16	Residential	106%	102%	115%
24	Small General Service	85%	102%	50%
36	Large General Service <1,000 kW	100%	102%	95%
48T	Large General Service >1,000 kW	100%	102%	115%
48T	Large General Service Dedicated Facilities	106%	102%	140%
40	Agricultural Pumping Service	85%	75%	50%
15,52,54,57	Street Lighting	28%	50%	0%

¹¹ Exhibit No.__(CTM-1T) at page 23; Exhibit No.__(MCD-1T) at pages 30-31.

¹² Exhibit No.__(CTM-1T) at page 26.

¹³ *Id.*

¹⁴ Exhibit No.__(MCD-1T) at pages 29-30.

1 larger users will pay higher energy prices under the inverted rate design while all
2 customers will pay a fair share of the overall price change.

3 **Q. Mr. Watkins discusses efficient pricing principles and recommends limiting the**
4 **increase in the basic charge to \$7.00 per month.¹⁶ How do you respond?**

5 A. In support of his position, Mr. Watkins relies on a number of misleading and
6 irrelevant assertions, most of which are inconsistent with policy and practice in
7 Washington. First, he argues that marginal costs should be used to set the basic
8 charge.¹⁷ However, since 1980, the Commission has only considered embedded cost
9 studies when making rate spread and rate design decisions.¹⁸ Mr. Watkins's focus on
10 marginal cost pricing is inconsistent with Commission precedent and is narrowly
11 considered for only one pricing element—the residential customer charge. This
12 piecemeal application ignores other potential outcomes for allocations and rates that
13 could be implicated by a marginal cost study and is therefore not reasonable. It
14 should also be noted that the Company's Oregon jurisdiction relies on marginal cost
15 studies for setting rates, and the Company's current residential basic charge in
16 Oregon is \$9.00. In a recent rate case all-party settlement stipulation in Oregon,
17 parties agreed to increase the basic charge to \$9.50 beginning January 1, 2014.

18 **Q. Mr. Watkins excludes corporate overhead costs from his calculation of a**
19 **residential basic charge.¹⁹ Do you agree that these costs should be excluded?**

20 A. No. First, to be clear, the corporate overhead costs included in the customer charge
21 calculation are only the portion of overhead costs that are allocated to customer-

¹⁶ Exhibit No.__(GAW-1T) at page 15.

¹⁷ *Id.* at page 6.

¹⁸ See Wash. Utils. & Transp. Comm'n Order Cause No. U-78-05.

¹⁹ Exhibit No.__(GAW-1T) at page 14.

1 related distribution costs in the COS study; they are not all overhead costs as may be
2 inferred from Mr. Watkins’s testimony. As I previously mentioned, no party
3 proposed changes to the COS study in this case.

4 Second, Mr. Watkins’s only rationale for removing these costs is that the
5 Company is “in the business of providing electricity to meet the energy needs of its
6 customers” and that “customers do not subscribe to PacifiCorp’s services simply to be
7 ‘connected.’”²⁰ This is an inadequate rationale. Overhead costs are a necessary part
8 of doing business. The Company cannot provide electricity to customers unless they
9 are connected. The costs of connecting and serving those customers—through
10 meters, services, and customer services—cannot exist without overhead costs. It is
11 appropriate to include the allocated share of overhead costs for the elements included
12 in the calculation of the basic charge.

13 **Q. Mr. Watkins asserts that “volumetric pricing promotes the fairest pricing**
14 **mechanism to customers and to the utility.”²¹ Do you agree with his assertion?**

15 A. No. The basis for Mr. Watkin’s assertion is the efficiency he assumes marginal cost
16 pricing would produce, which he admits ignores matters of equity.²² If the Company
17 is required to further increase its energy charges to compensate for a lower increase to
18 its basic charge, any benefits residential customers would be able to derive will not be
19 equitably distributed among residential customers. Households with lower energy
20 usage would be subsidized by households with higher energy usage. A cost-based

²⁰ Exhibit No. ___(GAW-1T) at page 14, lines 18-20.

²¹ *Id.* at page 6, lines 14-15.

²² *Id.*

1 residential basic charge will reduce intra-class subsidization and ensure that fixed
2 costs are fairly recovered from all customers.

3 **Q. Mr. Watkins uses the Federal Energy Regulatory Commission’s (FERC)**
4 **adoption of a “Straight Fixed Variable” (SFV) pricing method in Order 636,**
5 **which was intended for natural gas transmission pipeline companies, to suggest**
6 **that the Company’s proposed rate structure could hinder energy efficiency**
7 **goals.²³ Do you agree that this is an appropriate comparison?**

8 A. No. This comparison is irrelevant for many reasons. First, the Company did not
9 propose a SFV pricing structure. The Company is merely proposing an increase in
10 the residential basic charge to better reflect customer-related fixed costs. A SFV
11 pricing structure would result in a considerably larger fixed customer charge
12 component than the Company’s initial proposal of \$10.00, after taking into account
13 all generation, transmission and distribution related fixed costs. In the Company’s
14 proposed rates in this case, the vast majority of these costs—over 90 percent—will
15 continue to be collected through volumetric prices. Second, the purpose of FERC’s
16 adoption of SFV for pipeline companies was to eliminate potential distortions in
17 pipeline rate structures and stimulate competition at the wellhead for a national gas
18 market. FERC’s action for natural gas pipelines is simply not analogous to electric
19 residential consumers and rates. The purchasing decisions by gas transportation
20 customers and residential electricity customers are very different in scale and scope.

²³ Exhibit No.__(GAW-1T) at pages 8-9.

1 **Q. Mr. Watkins provides the example of competitive electric rates in Texas in an**
2 **attempt to show that competition leads to an increased emphasis on volumetric**
3 **rates.²⁴ Do you think this is relevant to the Company's proposed price**
4 **structure?**

5 A. No. First, Washington has not adopted a retail electric competition market like Texas
6 so it is not a relevant comparison. Second, the Company's proposal includes an
7 increase in volumetric rates as well as the basic charge; over 90 percent of total
8 residential revenues are recovered through volumetric rates. Third, even if the
9 Commission wished to consider this comparison, the information presented by Mr.
10 Watkins shows that 21 of the 28 electric providers in Texas waive their basic charge
11 if usage is above a certain threshold. For 18 of these 21, the threshold for waiving the
12 basic charge is at least 1,000 kWh a month, and the average of the basic charges these
13 utilities waive is \$9.50. Therefore, with the pricing structure presented by these 18
14 utilities in Texas, almost half of the Company's residential customers in Washington
15 would still likely pay a basic charge higher than what the Company is currently
16 proposing.

17 Finally, the introduction of evidence from Texas ignores important differences
18 between Texas and Washington, such as rate levels, weather patterns, income,
19 appliance mix, usage profiles, and regulatory policy. What creates more efficient
20 pricing in Texas will not necessarily improve the efficiency or equity of prices the
21 Company proposes for its residential customers in Washington. It would be more
22 relevant to compare the Company's proposed basic charge with the basic charges of

²⁴ *Id.* at 11-13.

1 other electric utilities in Washington. Exhibit No.____(JRS-14) shows the current
2 residential basic charges for other Washington utilities. It shows that the average
3 basic charge currently in effect for 44 of the electric utilities in Washington is
4 \$14.04—well above \$8.85 proposed by the Company in this rebuttal filing.

5 **Q. Mr. Mickelson proposes revising the current two-tier inverted energy charge**
6 **rate design by increasing the first tier from 0-600 kWh to 0-800 kWh and adding**
7 **a third tier for usage over 1,500 kWh.²⁵ Do you agree with this proposal?**

8 A. No. The Company has a number of concerns with this proposal. For one, to reset the
9 first tier, Mr. Mickelson relies on the upper-end range of average end-use
10 consumption for cooking, domestic hot water (DHW), lighting, and appliances from a
11 U.S. Department of Housing and Urban Development (HUD) Housing Choice
12 Voucher Program Guidebook from 2001.²⁶ Using upper-end national data from 2001
13 to reset the tier level in 2014 is incompatible with Washington’s (and the Pacific
14 Northwest’s) historically aggressive energy efficiency efforts and may not be
15 reflective of what the less elastic essential end-uses are in the Company’s Washington
16 service area today. Additionally, the Company disagrees with including DHW in the
17 first tier. Based on the Company’s last residential usage survey, about 30 percent of
18 the Company’s residential customers do not have electric water heat. Including
19 average DHW consumption in the first tier fails to acknowledge that about one third
20 of residential customers do not have electric water heat.

21 Before residential energy charge tiers can be updated, new residential end-use
22 saturation data for our Washington service area must be captured. The last residential

²⁵ Exhibit No.____(CTM-1T) at page 33.

²⁶ *Id.* at 33-34.

1 survey was completed in 2006. A new survey ordered by the Commission would
2 better inform residential rate design decisions for Washington than relying on
3 national HUD data from 2001.

4 **Q. Are there other reasons you disagree with Mr. Mickelson’s proposal to reset**
5 **residential energy charge rate tiers in this case?**

6 A. Yes. As Mr. Mickelson notes, moving more usage into the first tier as he proposes
7 reduces the conservation price signal because more consumption can occur at a lower
8 rate.²⁷ There is no compelling reason to send this confusing price signal to customers,
9 particularly in light of Washington Initiative I-937. The Company’s conservation
10 programs target many types of end uses so altering this rate design may actually
11 undermine those energy efficiency program efforts.

12 Moreover, while Mr. Mickelson argues that adding the third tier may help
13 with conservation efforts for higher-use customers,²⁸ he does not recognize that the
14 Company’s current residential rate design already reflects a steeply inverted tail block
15 rate. The Company’s current second tier energy rate is 58 percent higher than the
16 first tier; the Company’s proposed rate design in this case increases the differential to
17 be 73 percent higher. In contrast, the second tier in PSE’s current residential tariff
18 Schedule 7, which is also set for 0-600 kWh, is 22 percent higher than the first tier.²⁹
19 Avista, which has three residential energy tiers, has an even flatter rate structure with
20 the second tier (for usage between 800-1500 kWh) only 16 percent higher than the

²⁷ Exhibit No.__(CTM-1T) at page 34.

²⁸ *Id.* at 35.

²⁹ See Puget Sound Energy, Inc., Tariff WN U-60, Schedule 7, effective July 1, 2013: the energy charge for tier one (0-600 kWh) is 8.5578¢ per kWh and tier two (over 600 kWh) is 10.4157¢ per kWh.

1 first tier and the third tier only 17 percent higher than the second tier.³⁰ The
2 difference between the first and third tiers for Avista is 36 percent, which is
3 significantly less than the differential in the Company’s current rate design.

4 Mr. Mickelson’s proposed rates in this case actually reduce the differential
5 between the first and second tiers to 50 percent and have a very modest differential of
6 only seven percent between the second and third tiers. Thus, the rate differential
7 between his proposed first and third tiers is less than the differential between the
8 Company’s proposed rates for the first and second tiers. Therefore, the Company’s
9 current and proposed rate design provides a more significant price signal to not only
10 higher usage customers but also to more residential customers overall.

11 **Q. Mr. Mickelson argues that his proposed residential rate design promotes**
12 **revenue stability.³¹ Do you agree?**

13 A. Not necessarily. While the Company appreciates Mr. Mickelson’s interest in
14 promoting revenue stability, creating a third tier with a higher rate does not
15 necessarily lead to more stable or predictable revenue. The third tier may increase
16 revenue volatility as it would be more subject to changes in temperature and
17 economic activity than the first and second tiers. The best and most efficient way to
18 promote revenue stability is to reflect fixed costs through the fixed monthly basic
19 charge.

20 Additionally, the rates Mr. Mickelson proposed are not consistent with the
21 rate design he recommended in testimony. Mr. Mickelson recommends “creating a

³⁰ See Avista Corporation Tariff WN U-28, Schedule 1, effective January 1, 2013: the energy charge for tier one (0-800 kWh) is 7.133¢ per kWh, tier two (801-1,500 kWh) is 8.299¢ per kWh and tier three (over 1,500 kWh) is 9.728¢ per kWh.

³¹ Exhibit No.__(CTM-1T) at page 39.

1 third block volumetric rate using the exact same cents per kWh differential between
2 the first- and second-block rates before the rate increase, and then applying a
3 weighted uniform percentage increase for all volumetric rates in all Residential
4 Schedules based on each block's kilowatt-hour units."³² However, Mr. Mickelson's
5 proposed energy rates for the third block are not designed with the "exact same cents
6 per kWh differential" as in the first and second blocks.³³ To design rates as Mr.
7 Mickelson describes in testimony would actually require a decrease in the first tier
8 rate from the current rate in order to create an equal cents/kWh differential between
9 the second and third tier rates; otherwise, the rates would collect too much revenue.
10 A lower first tier rate would result in a lower percentage of revenue in the first block
11 than what Mr. Mickelson shows on Table 5, and thus would be contrary to his
12 argument that his rate design would improve rate stability.

13 **Q. Does the Company have additional concerns with Mr. Mickelson's rate design**
14 **recommendations?**

15 A. Yes. Adoption of Mr. Mickelson's proposed rate design to change the first block
16 from 0-600 kWh to 0-800 kWh and the creation of a third tier could require a
17 redesign of Schedule 17, the Company's Low Income Bill Assistance (LIBA)
18 program. Schedule 17, was designed to reflect the two-tier energy charge rate design
19 for Schedule 16 residential rates with a rate credit applied to usage greater than 600
20 kWh for qualifying customers during winter months (November 1 through April 30).
21 Since not all customers on Schedule 17 have monthly usage that exceeds 800 kWh,
22 some customers would be adversely impacted by application of Mr. Mickelson's

³² Exhibit No.__(CTM-1T) page 36.

³³ The current differential between the first and second tiers is 3.5¢/kWh, whereas the differential between Mr. Mickelson's proposed second and third tiers is less than 1¢/kWh.

1 proposed rate design to Schedule 17 because they would not receive a low income
2 credit in some months.

3 In addition, the Company is also concerned that Mr. Mickelson's proposal to
4 add a third residential tier and increase the second tier was not included in the
5 required notice to customers for this case; therefore, residential customers that would
6 be affected would have not had an opportunity to comment before implementation.

7 **GENERAL SERVICE, AGRICULTURAL PUMPING**
8 **AND STREET LIGHTING RATE DESIGN**

9 **Q. Is the Company proposing any changes in this rebuttal filing to rate designs for**
10 **the general service, agricultural pumping, and street lighting schedules?**

11 A. No. No party opposed the Company's proposed rate design for these schedules, and
12 the Company is not proposing any changes from those in my direct testimony.
13 Exhibit No.____(JRS-11) contains the proposed prices based on the updated revenue
14 requirement. For General Service Schedule 24 the Company proposes to apply
15 uniform percentage increases to the basic, demand, and energy charges. For General
16 Service Schedules 36 and 48T, the Company has applied a larger increase to the
17 demand charges based on the results of the COS study. Other charges in Schedule 36
18 and 48T have been increased on a uniform basis to recover the balance of the
19 allocated increase to each schedule. For Agricultural Pumping Service Schedule 40
20 the Company proposes to reflect the revised revenue requirement by increasing the
21 Load Size charge and the Energy Charge by approximately an equal percentage. For
22 lighting schedules, the Company proposes a uniform increase to all lighting
23 schedules.

1 **ADJUSTMENT TO ANNUALIZE REVENUES**

2 **Q. Mr. Dittmer’s proposed revenue normalization adjustment attempts to**
3 **annualize revenues using the number of customers at the end of the test year.³⁴**

4 **Does the Company agree that this is a reasonable methodology?**

5 A. No. Mr. Dittmer’s proposal does not properly capture present revenues in this case.
6 The Company’s calculation of normalized revenues is consistent with the
7 Commission’s long-established and well-understood ratemaking practices. It is based
8 on actual historical revenues from the base year, normalized to reflect rate changes
9 during the base year. The Company does not serve a static number of customers set
10 for one point in time, which is what Mr. Dittmer’s calculation attempts to do.
11 Mr. Dittmer’s proposed approach fails to recognize customer changes including
12 seasonal customers throughout the year. The Company’s methodology correctly
13 captures customer variation throughout the year and is reasonable.

14 Additionally, Mr. Dittmer’s proposal fails to capture changes in load that may
15 be associated with changes in the number of customers. In states where the Company
16 utilizes forecast test periods, forecast revenues are calculated using a forecast of both
17 customers and usage. Mr. Dittmer’s approach is therefore inconsistent with both
18 historical and forecast test period revenue normalization approaches. Mr. McDougal
19 further addresses this adjustment in his rebuttal testimony.

20 **Q. Does this conclude your rebuttal testimony?**

21 A. Yes.

³⁴ Exhibit No.__(JRD-1T) at page 11.