

EXHIBIT NO. _____ (AML-1T)
DOCKET NOS. UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: AMANDA M. LEVIN

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

DOCKET NOS. UE-170033
and UG-170034 (*Consolidated*)

PREFILED RESPONSE TESTIMONY (NON-CONFIDENTIAL) OF

AMANDA M. LEVIN

ON BEHALF OF NW ENERGY COALITION, RENEWABLE NORTHWEST, AND

NATURAL RESOURCES DEFENSE COUNCIL

JUNE 30, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Amanda Levin. I am an Energy and Climate Analyst for the Natural Resources Defense Council, 1152 15th Street NW, Suite 300, Washington, D.C., 20005.

Q. In what capacity are you submitting this testimony?

A. I am a witness for the NW Energy Coalition, Renewable Northwest, and Natural Resources Defense Council (“the Coalition”).

Q. Have you previously testified before the Washington Transportation and Utilities Commission (“Commission”)?

A. No.

Q. Have you prepared an exhibit describing your education, relevant employment experience and other professional qualifications?

A. Yes, I have. It is Exhibit No. ____ (AML-0).

II. SUMMARY OF TESTIMONY

Q. Please explain the purpose of your testimony.

A. My testimony focuses on five topics: 1) the proposed increase in the residential electric customer charge; 2) the three-tier block rate design for the residential electric rate schedule; 3) the inclusion of fixed power costs in PSE’s decoupling mechanism; 4) the proposed lifting of the decoupling mechanism’s rate test trigger from 3 to 5 percent; and 5) PSE’s Low-Income program funding increase.

Q. Please briefly summarize the key recommendations of your testimony.

A. In my testimony, I make five recommendations.

First, I oppose PSE’s requested increase to the monthly basic charge for residential electric service. PSE improperly includes the costs of distribution line transformers as customer-

1 related, against previous commission orders on the classification of transformer costs. Excluding
2 these distribution line transformers costs results in revised customer-related costs of \$7.99 per
3 month, in line with PSE’s current monthly basic charge. Thus, there is no need for PSE to
4 increase the basic charge for residential electric customers.

5 Second, I propose an alteration to PSE’s calculation of a three-tier block rate for
6 residential electric customers. PSE should explore revising the “avoided long-term costs of
7 power and capacity” to reflect the carbon costs of necessary energy and capacity purchases
8 and/or better account for load shape differences between low-energy and high-energy users.
9 High-energy users are largely space heating and space cooling customers with very peak-
10 oriented usage patterns. If, with the alterations discussed below, the three-tier block rate
11 conforms to a proper, inclining block rate, I would support the transition of residential rates from
12 the current two-tier design to the revised three-tier block rate design.

13 Third, I oppose the inclusion of fixed power costs in PSE’s decoupling mechanism, as
14 currently proposed. PSE has a revenue per customer (RPC) decoupling mechanism where
15 allowed revenue grows with customer growth. This is appropriate when only distribution costs
16 are recovered through a decoupling mechanism—as these costs increase with increased customer
17 count. However, unlike distribution costs, fixed power costs would be expected to decline (on a
18 per capita basis) between rate proceedings as existing power plants depreciate. Including these
19 fixed plant costs within a RPC approach can result in over-recovery of these costs. While I have
20 concerns with this inclusion, I am wholly supportive of the company continuing a decoupling
21 mechanism and the Company’s ability to recover these fixed power costs. Therefore, I provide
22 two possible suggestions that would help address the potential for over-recovery of these fixed
23 plant costs under PSE’s RPC mechanism.

1 I also oppose PSE’s proposal to lift the decoupling mechanism rate test trigger from 3 to
2 5 percent, on the electric side. Unlike for the gas decoupling mechanism, I find no history of
3 issues with a 3 percent cap and little concrete support for PSE’s decision to lift the rate test
4 trigger from 3 to 5 percent for electric decoupled rate classes. I also call on PSE to revise its
5 weather forecasting methods for gas service, which may help alleviate the large deferrals seen
6 for residential gas service. The Commission should oppose the proposed change for the electric
7 side unless there is definitive evidence that the 3 percent cap is unduly impacting PSE’s ability to
8 recover authorized costs.

9 Lastly, I support PSE’s proposed changes to its low-income assistance program, HELP,
10 as well as PSE’s proposal to continue its higher funding levels for the company’s low-income
11 weatherization program.

12 III. MONTHLY BASIC CHARGE ISSUES

13 **Q. What topics will you address in this section of your direct testimony?**

14 A. In this portion of my testimony, I address PSE’s proposal to increase the monthly basic
15 charge from \$7.49 to \$9.00 for electric residential customers.¹

16 **Q. Do you agree with the way PSE calculated customer-related costs for electric
17 residential service?**

18 A. No. PSE classifies three distinct distribution costs as “customer-related”; meaning that
19 they do not vary with customer energy use. These include: costs of meters, service lines, and
20 distribution line transformers.² All other distribution costs are considered to be “demand-
21 related” for the residential class. PSE seeks to recover these “customer-related” costs through the
22 monthly basic charge. I disagree with PSE’s classification of distribution line transformers as

23 ¹ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 59.

24 ² Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 30.

1 “customer-related.”

2 **Q. What method would you suggest PSE use instead?**

3 A. PSE should use the Basic Customer method. The Commission has consistently adopted
4 the Basic Customer method for classification of distribution plants.³ Indeed, in 1992, when
5 NARUC issues a new cost allocation handbook, the Commission took strong issue with the
6 exclusion of this method. This is documented in Exhibit No. ____ (AML-3), which is the
7 WUTC’s June, 1992 letter to the Chair of the relevant NARUC Committee, and states:

8 Our Commission has been extremely clear about one thing in this
9 area: that the ‘minimum-distribution’ and ‘minimum intercept’
10 methods are not acceptable, and that the only costs which should
be considered customer-related are the costs of meters, services,
meter reading, and billing.

11 **Q. What is PSE’s justification for this radical departure from Commission-accepted
12 practice?**

13 A. PSE states that it has classified line transformer costs as “customer-related” for the last
14 four rate cases.⁴ However, the last four rate cases have all been settled amongst the parties via
15 stipulation settlements. The Commission has not directly addressed this issue for decades, and
16 PSE concedes that the Commission has never given express approval of this treatment of line
17 transformer costs.⁵ Looking back at previous Commission orders, the Commission has not
18 historically considered line transformer costs as “customer-related” and instead adopted the
19 Basic Customer method for classification of costs as customer-related.

20 The Commission has stated, in previous dockets:

21 _____
22 ³ Cause U-89-2688-T, Third Upp. Order, pg.71; Docket No. UE-920499, Ninth Supplemental Order on
Rate Design, pg. 11.

23 ⁴ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 33.

24 ⁵ Exhibit No. ____ (AML-4), PSE Response to NWEC-RNW-NRDC Data Request No. 043.

1 In this case, the only directive the Commission will give regarding
2 future cost of service studies is to repeat its rejection of the
3 inclusion of the costs of a minimum-sized distribution system
4 among customer-related costs. As the Commission stated in
5 previous orders, the minimum system method is likely to lead to
6 the double allocation of costs to residential customers and over-
7 allocation of costs to low-use customers. Costs such as meter
8 reading, billing, the cost of meters and service drops, are properly
9 attributable to the marginal cost of serving a single customer. The
10 cost of a minimum sized system is not. The parties should not use
11 the minimum system approach in future studies.⁶

7 The Commission finds that the Basic Customer method represents
8 a reasonable approach. This method should be used to analyze
9 distribution costs, regardless of the presence or absence of a
10 decoupling mechanism. We agree with Commission Staff that
11 proponents of the Minimum System approach have once again
12 failed to answer criticisms that have led us to reject this approach
13 in the past. We direct the parties not to propose the Minimum
14 System approach in the future unless technological changes in the
15 utility industry emerge, justifying revised proposals.⁷

12 PSE states that it classifies line transformers as customer-related because: “(1) transformer sizes
13 are standardized, (2) line transformers are installed and sized specifically to serve a particular
14 customer or group of customers, and (3) transformers are rarely re-sized for a particular customer
15 or a group of customers.”⁸ However, PSE’s explanation ignores both that transformer costs,
16 over a sufficiently long period, do vary based on energy usage, and that the incremental
17 connection costs for small, residential customers are really limited to only the installation and
18 maintenance of costs of a meter, and possibly, service drop.

19 **Q. Can you provide more detail regarding why the cost of line transformers should not**
20 **be included in the basic charge?**

21 A. First, line transformer costs should not be characterized as customer-related because a

22 _____
23 ⁶ Cause U-89-2688-T, Third Supp. Order, pg. 71.

24 ⁷ Docket No. UE-920499, Ninth Supp. Order on Rate Design, pg. 11.

⁸ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 33.

1 single transformer serves widely varying numbers of customers and because the need for
2 transformers depends at least in part on energy usage.

3 Individual line transformers serve as few as one customer and as many as twenty. In a
4 rural setting, it is not practical to use low-voltage lines to connect multiple properties, so a
5 separate transformer is installed for each customer. In a suburban setting of single-family
6 homes, a single transformer normally serves 5–10 customers, and utilities take into account both
7 the spacing between homes and the demand diversity between homes in choosing where to
8 install transformers and the transformer capacity required. In an urban or multi-family setting, a
9 single transformer or transformer bank may serve 20 to 100 separate “customers” as each unit in
10 an apartment building is separately metered pursuant to the Commission’s 1980 decision in
11 Cause U-78-05 where it adopted the master-metering standard of PURPA.⁹

12 Additionally, as has been detailed in several sources,¹⁰ lines transformers are volume-
13 driven,¹¹ with the construction, size, and necessary upgrades of transformers ultimately
14 dependent on expected load. Changes in customer demand can change the lifetime and cost of
15 transformers over a sufficiently long period. Transformer sizing and costs are driven to meet
16 customer demands during peak times when transmission and distribution (T&D) equipment is
17 heavily-loaded, and should be appropriately recovered through billing determinants that vary, at
18 least roughly, with the customers’ contribution to load in those hours. Small use customers, such
19 as apartments with 20 or more customers per transformer have a much lower cost responsibility

20
21 ⁹ Commission Decision and Order No. 1 in Cause No.U-78-05, filed on October 29, 1980.

22 ¹⁰ Direct Testimony of Paul Chernick, Rulemaking 12-06-013 before the PUC of the State of California.
23 September 15, 2014; Regulatory Assistance Project’s “Smart Rate Design for a Smart Future”,
24 <http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf>.

¹¹ Lazar, Jim, et. al., “Pricing Do’s and Don’ts: Designing Retail Rates As if Efficiency Counts,”
<http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-pricingdosanddents-2011-04.pdf>.

1 for transformers than suburban properties with 5-10 customers per transformer. Similarly,
2 suburban customers have a lower cost responsibility for transformers than rural properties.

3 Even regardless of the classification of transformer costs, a basic service charge should
4 serve to recover only the incremental costs imposed by the presence of a new customer, not all
5 customer-related expenses. In the case of a small customer, such as a residential customer, the
6 incremental cost of connecting the customer should not typically require the company to build
7 additional transformers, with the incremental costs of connecting the customer reflecting the
8 installation of the final service drop and meter, at most.

9 There are many equitable ways to recover transformer costs, but “per customer” is not
10 one of them. This could be done through either demand or energy charges, but it cannot be done
11 through fixed charges. For residential (small) customers, recovering these volume-driven costs
12 through a volumetric energy charge is a good choice.¹² In this case, I recommend that these
13 transformer costs be classified in the same manner as those for poles and conductors for the
14 residential electric class.

15 **Q. How does the exclusion of these line transformer costs from customer-related costs**
16 **change the estimated basic charge for electric residential customers?**

17 A. As part of discovery, PSE was asked to recalculate the Basic Charge with transformers
18 treated as demand-related instead of customer-related.¹³ With the exclusion of transformer costs,
19 the adjusted Schedule 7 customer-related cost is reduced from \$11.24 to \$8.07, which is more
20 consistent with PSE’s current basic charge of \$7.49.

21 _____
22 ¹² Regulatory Assistance Project’s “Smart Rate Design for a Smart Future”, <http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf>;
23 http://www.brattle.com/system/publications/pdfs/000/005/345/original/Curating_the_Future_of_Rate_Design_for_Residential_Customers.pdf?1469036198.

24 ¹³ Exhibit No. ____ (AML-5), PSE Response to NWECC-RNW-NRDC Data Request No. 036.

1 In addition, as I will discuss more below, the per-customer costs for serving and
2 connecting multi-family consumers is likely lower than the \$8.07 monthly figure. For example,
3 if an existing single-family home is divided into a primary dwelling unit and an accessory
4 dwelling unit (i.e., “mother-in-law apartment”), the only incremental investment needed is a
5 second meter, and the rendering of a second bill; no incremental investments for a service drop
6 would be necessary. However, the costs of installing and maintaining a service drop are still
7 included in the adjusted basic charge.

8 I recommend that the Commission reject the company’s proposal to increase the Basic
9 Charge for residential customers. With the proper treatment of transformer costs as demand-
10 related, the adjusted customer-related costs are most in-line with the current basic charge of
11 \$7.49. Furthermore, this charge is currently applied to all residential customers, including both
12 multi-family and single-family households, although multi-family may have lower customer-
13 related costs (due to the shared service drop). Without separate treatment for the single and
14 multi-family dwellings, the Commission should err on the side of lower basic charges to ensure
15 the fixed charge appropriately reflects the true customer costs incurred by the smallest residential
16 customers.

17 **Q. Have you attempted to measure whether there are real differences in the cost of**
18 **servicing single-family versus multi-family consumers?**

19 A. Yes. We did some basic discovery on this.¹⁴ The table below compares the number of
20 customers per transformer for transformers serving multiple customers versus those serving a
21 single residential address. They show very clearly that transformer costs are not purely
22 customer-related:

23 _____
24 ¹⁴ Exhibit No. ____ (AML-6), PSE Response to NWEK-RNW-NRDC Data Request No. 040.

	Serving multiple customers	Serving a single residential address
Transformers	197,503	47,699
Customers	1,054,296	47,699
Customers/transformer	5.34	1

Q. Are you aware of any utilities that charge different rates for single-family versus multi-family consumers?

A. Yes. One example is Nevada. The Nevada Energy tariff for multi-family customers has a monthly customer charge that is half that of the customer charge for single-family homes.¹⁵ This is due to recognition that both customer costs and distribution costs are lower to multi-family customers.

Q. Are there other reasons to constrain the basic charge?

A. While parties may see fixed charge increases as a quick and simple way to address revenue deficiency, increasing the fixed charge presents numerous problems for consumers, the utility, energy efficiency, and other clean energy programs.

Evidence from other commissions supports the conclusion that increasing fixed charges has a disproportionate impact on low-volume, lower income customers.¹⁶ High fixed charges also reduce consumers' ability to voluntarily take measures to reduce energy bills, lessening the financial incentive to reduce electricity consumption. Higher fixed charges send the wrong price signal to customers, discouraging individuals from investing in energy efficiency measures or

¹⁵ Nevada Energy has a Schedule No. DM-1 for Multi-family service and a Schedule No. D-1 for single-family residential service. The basic charge for Multi-family is less than half of that for a single family. <https://www.nvenergy.com/company/rates/nnv/electric/schedules/>.

¹⁶ Testimony of John Howat in Case No. 15-00261-UT before the New Mexico Public Regulation Commission.

1 conservation.¹⁷ This undermines customer incentives to change usage patterns and reduce
2 energy waste that would help consumers and the utility avoid increased investments in high cost
3 generation and grid investments over the long-term.

4 The Commission has noted these perverse financial incentives itself in the 2015
5 PacifiCorp decision, where it rejected the Company's and Staff's proposals to increase the
6 residential basic charge:¹⁸

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

15 While increasing the fixed charge may address revenue deficiency from reductions in
16 consumer energy consumption in the short-term, it results in undesirable impacts on consumers
17 and creates perverse consumer incentives that hinder the adoption and implementation of energy
18 efficiency measures and actions that promote smart energy conservation.

19 The Commissions should continue to ensure that basic charges only reflect "direct
20 customer costs." In this proceeding, PSE's basic charge should be limited to only the costs of
21 meter reading, billing and customer service, and the installation and maintenance of the service
22 drop and meter. The basic charge should not include the cost of the transformer.

23 **Q. Please summarize your recommendations with respect to the basic charge.**

24 _____
25 ¹⁷ America's Power Plan, "Economic concerns about high fixed charge pricing for electric service,"
October 2014, <http://americaspowerplan.com/wp-content/uploads/2014/10/Economic-analysis-of-high-fixed-charges.pdf>; Borenstein, Severin, "What's so Great about Fixed Charges?" Energy Institute at Haas,
November 2014, <https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/>.

¹⁸ WUTC Docket UE-140762, Order 08.

1 A. First, I recommend that no increase be applied to the basic charge.

2 Second, I recommend that the Commission direct PSE to study the difference in the
3 residential cost of service between three separate categories of residential customers:

4 (a) rural single-family customers, those located outside of urban boundaries;

5 (b) suburban single-family customers located within the city limits of the
6 communities it serves; and

7 (c) multi-family customers;

8 This study should also include an in-depth examination of low income customers, including low
9 and high usage households.

10 The company should submit a report with its findings within a year of the conclusion of
11 this proceeding, so it can guide future rate changes. I am not recommending PSE or the
12 Commission make any specific rate changes in response to any study findings. The purpose of
13 the study is to provide further granular information so that interested parties and the
14 Commissions can make knowledgeable decisions in the future about how specific rate changes
15 would impact different customers within the residential class.

16 IV. RESIDENTIAL RATE DESIGN

17 **Q. What topics will you address in this section of your direct testimony?**

18 A. In this portion of my testimony, I address PSE's calculation of a three-tier block rate
19 structure for its electric residential customers.¹⁹ I propose two alterations to the company's
20 three-tier design to better align the three tiers with conservation goals.

21 **Q. How does your testimony on rate design fit with the recent Motion to Amend Order**
22 **03 and Settlement Agreement filed in Docket UE-141368?**

23 _____
24 ¹⁹ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 59.

1 A. On July 29, 2017, PSE and other parties, with the exception of Northwest Energy
2 Coalition, filed a Joint Motion to Amend Order 03 and Settlement Agreement in Docket UE-
3 141368—a prior rate design docket filed by PSE. The 2014 settlement agreement required PSE
4 to propose a specific three-tier rate structure in its next general rate case, which PSE did here.
5 The joint motion asks the Commission to eliminate the requirement for a residential electric
6 three-tier block rate design. My testimony below addresses concerns with PSE’s proposed three-
7 tier rate design. If the Commission grants the motion to amend the prior order and settlement
8 agreement, PSE presumably will seek to revert to the two-tier rate structure that has been in
9 place for many years. As the motion was filed a day before the due date for response testimony,
10 and as the Commission will not rule on the motion prior to submission of this response
11 testimony, my testimony does not address the two-tier rate structure. If the motion is granted,
12 my testimony will still be relevant as the moving parties’ proposal is that any party remains free
13 to propose any rate design the party wishes. The Commission should continue to consider the
14 benefits of a three-tier block rate design, with the modifications suggested below, as opposed to
15 the previous two-tier structure.

16 **Q. How does PSE calculate the three-tier block rate in the current proceeding?**

17 A. PSE first calculated the rate for the third tier (usage above 1,800 kwh), using the
18 estimated long-run avoided cost of power and delivery.²⁰ The first- and second-tier rates were
19 then adjusted until the price of these two blocks, when accounting for the monthly basic charge
20 and third-tier rate, allowed PSE to recover the full revenue requirement spread to electric
21 residential customers. PSE kept the current differential (~2 cents per kWh) between first and
22 second tier when adjusting the tiered rates.

23 _____
24 ²⁰ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 59.

1 The long-run avoided cost of power and delivery is calculated based on the 20-year
2 levelized cost of avoided energy (based on forecasted market prices), avoided renewable energy,
3 deferred T&D capacity, avoided generation capacity, line losses, and a statutory 10 percent adder
4 for conservation benefits.

5 Using this approach, PSE arrives at a third-tier rate of \$0.097774 per kWh.²¹ This rate is
6 below the rate of the second-tier. PSE rightly concludes that implementing a three-tier rate
7 where the second-tier rate is higher than the third tier (long-run avoided cost) may not be
8 appropriate.²² I concur with PSE that implementing a three-tier rate with a lower-cost third tier
9 would send perverse conservation incentives for consumers.

10 **Q. What suggestions do you have on how to improve the three-tier block rate?**

11 A. I propose two alterations to the calculated third-tier rate. Both these calculations should
12 increase the estimated long-run avoided cost of energy and delivery, and hopefully resolve the
13 issues noted by PSE in its filings. If these alterations result in a more appropriate, inclining
14 three-tier block rate, I would recommend PSE and the commission approve a three-tier rate for
15 residential customers.

16 First, PSE should account for the expected carbon emissions of an MWh of delivered
17 energy, including energy line losses. As part of discovery, PSE recalculated the third-tier rate
18 using the Mid-CO₂ price forecast from the company's 2015 IRP.²³ The CO₂ price was
19 incorporated in the company's annual weighted average of hourly price. As a result, the long-

21 ²¹ Supplemental Filing by Jon A. Piliaris, Exhibit No. ____ (JAP-34T).

22 ²² Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 59.

23 ²³ The company uses three CO₂ forecasts in its IRP. *See* Exhibit No. ____ (AML-7), chapter 4 of the 2015
24 IRP, available at https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_Chap4.pdf. The Mid-
CO₂ price case starts at \$13 a ton in 2016, rising to \$54 per ton in 2035. The High-CO₂ price case starts at
\$35 a ton in 2016, rising to \$102 per ton in 2035.

1 run avoided cost increased from 9.77 cents to 10.82 cents per kwh.²⁴ While this is still lower
2 than the current second tier, the company could instead use its 2015 IRP high CO₂ price forecast,
3 which reflects a carbon price about double or more than the mid-case. PSE would need to
4 develop a revised power price forecast to incorporate the high-CO₂ price forecast into its third-
5 block rate calculation.²⁵ Accounting for the carbon emissions of long-term energy and capacity
6 needs would send a more appropriate signal to consumers of the long-term costs of new energy
7 and capacity, given the likelihood of state, regional, and/or federal carbon policies over the next
8 20 years.

9 Second, if feasible, PSE should differentiate the costs between low- and high-energy
10 users, accounting for the load factors of these different residential customers, as well as any
11 difference in coincident and non-coincident peak demand.²⁶ This is the foundation of PSE's
12 original inclining block rate, adopted in 1975. The estimated long-term costs for avoided energy
13 and capacity should reflect the load factor and demand profile of these high-energy users within
14 the residential class.

15 **Q. How would load factor and shape affect the cost of the residential rate tiered**
16 **blocks?**

17 A. There are two different elements. First, usage in winter, PSE's peak season, is generally
18 more expensive from a distribution capacity planning perspective. High use residential
19 customers are most likely electric heat customers whose usage is very weather-sensitive, and
20 require additional distribution capacity that is seldom used. Second, because high use is

22 ²⁴ Exhibit No. ____ (AML-8), PSE Response to NWECC-RNW-NRDC Data Request No. 049, Attach. A.

23 ²⁵ Exhibit No. ____ (AML-9), PSE Response to NWECC-RNW-NRDC Data Request No. 050.

24 ²⁶ PSE states it does not currently have this information available. See Exhibit No. ____ (AML-10), PSE
Response to NWECC-RNW-NRDC Data Request No. 047.

1 weather-sensitive, it also creates additional generation capacity requirements. But, again, this
2 capacity is seldom used. The higher third block price must reflect the recovery of this capacity
3 over the relatively short periods of usage for peaking resources. High levels of usage occur
4 during peak periods, driven by weather, and the cost of providing capacity for that seldom-
5 experienced usage is higher than for stable, year-round usage such as lights and appliances
6 covered by the first block.

7 **Q. Please summarize your recommendations concerning the three-tier rate design.**

8 A. I recommend that PSE completes further calculation of a three tier rate using a higher
9 carbon price, such as the High CO₂ price forecast used in its IRP. I also recommend that PSE
10 consider ways it may be able to better reflect the load factor and usage profiles of high use
11 customers for the third block rate calculation. This would require additional data collection and
12 analysis not currently undertaken by PSE, but necessary to determine more granular details on
13 the usage patterns of high-use residential customers.

14 V. COMMENTS ON DECOUPLING MECHANISM

15 **Q. What topics will you address in this section of your testimony?**

16 A. I will address two of the company's proposed changes to the decoupling mechanism in
17 my testimony. First, I will address the inclusion of fixed power costs in the company's
18 decoupling mechanism. Second, I will address PSE's proposal to increase the decoupling
19 mechanism's rate test trigger from 3 to 5 percent.

20 **Q. Are you opposed to PSE continuing its decoupling mechanism?**

21 A. No. I support a decoupling mechanism for PSE; nothing in this testimony should be
22 taken as opposition to continuing PSE's decoupling mechanism. Decoupling is an important
23 feature that ensures utilities have proper incentives to pursue all cost-effective energy efficiency
24 opportunities and should be preserved in the State of Washington.

1 **Q. What evidence is there that PSE’s decoupling has been successful?**

2 A. As part of PSE’s electric and natural gas decoupling settlement (UE-121697 and UG-
3 121705), PSE agreed to fund a third-party evaluation of PSE’s decoupling mechanism for the
4 initial program period. The evaluation reviewed the impacts of the decoupling rider on
5 consumers, on low-income consumers specifically (defined as bill-assisted consumers), and on
6 conservation program performance. PSE completed both a second-²⁷ and third-year²⁸ evaluation,
7 which both came to similar conclusions. Overall, the findings strongly support the continuation
8 of this program:

- 9 • The third-party evaluators confirmed the decoupling mechanism has worked as
10 intended.
- 11 • The size of decoupling adjustments was small – small enough to not noticeably
12 impact customer incentives to conserve energy.
- 13 • There was no significant difference in decoupling impacts for low-income
14 residential consumers and non-bill assisted residential consumers.
- 15 • The third-party evaluator did not find any conclusive evidence to suggest that
16 the decoupling mechanism has any adverse effects,²⁹ building off the earlier
17 finding that “decoupling for the [first] two years studied is, in a word,
18 *harmless.*”³⁰

21 ²⁷ WUTC Docket UE-121697, “Second Year Evaluation of PSE’s electric and gas decoupling
22 mechanisms, on behalf of Puget Sound Energy, from Ken Johnson.” Reported published on June 7, 2016.

23 ²⁸ Direct Testimony and Exhibits of Jon A. Piliaris, Exhibit No. ____ (JAP-29).

24 ²⁹ See Direct Testimony and Exhibits of Jon A. Piliaris, Exhibit No. ____ (JAP-29), pg. 20.

25 ³⁰ See Johnson, Second-Year Evaluation, pg. 7.

- The evaluators found no evidence of adverse impacts on customer service or on the utility’s incentives to control costs or on operational efficiency. In fact, PSE’s annual average increase in O&M costs has declined when compared to the historical growth rate.
- Decoupling has helped support “an organizational reality in which it is ok for staff to exceed savings goals and in which DSM and renewable energy are included in a positive organizational outlook.”

Taken together, the second- and third-year evaluations indicate that decoupling has had a net beneficial impact for consumers, the utility, and conservation. In my opinion, the findings of the second and third-year evaluation strongly supports the continuation of PSE’s decoupling mechanism.

Q. Have other utilities’ experiences with decoupling been similarly successful?

A. Yes. Since PSE first received approval for its latest decoupling mechanism, decoupling has gained a foothold in the U.S. At the beginning of 2013, 13 states and DC had at least one decoupled electric utility, involving 24 electric utilities. As of June 2017, 16 states and Washington D.C. had at least one decoupled electric utility. In total, 36 electric utilities are now decoupled (33 investor-owned and 3 public utilities).³¹ Decoupled investor-owned electric utilities now serve over 37 percent of all customers with investor-owned electric utilities, up from a little less than 25 percent at the beginning of 2013.³²

In addition to new and expected decoupling orders, several recently decoupled utilities

³¹ This number reflects only states with non-expired decoupling mechanisms. States include CA, CO (Approved June 21, 2017), CT, HI, ID, ME, MD, MA, MN, NY, OH, OR, RI, VT, WA, and DC, as well as IL (where decoupling is required under a December 2016 law). A total of 18 states and DC have instituted decoupling for one or more electric utilities at some point in time. Decoupling is currently discontinued in Wisconsin and Michigan. In total, 40 electric utilities have been decoupled at some point.

³² Calculations based on EIA Form 861 filings using data from 2014.

1 have completed either third-party or utility evaluations of their revenue decoupling mechanisms
2 in the last year. These evaluations provide more robust evidence on the impacts of revenue
3 decoupling on all consumers, low-income consumers, and energy efficiency, and contribute to a
4 greater understanding of the net benefits and impacts on risk to consumers and utilities under
5 decoupling.

6 For example, an ACEEE review³³ of performance incentives found that decoupling had
7 a significant impact on energy efficiency savings: decoupled utilities achieved an average of
8 1.4% annual energy savings, compared to non-decoupled, non-LRAM utilities' average of
9 0.5% savings. And decoupled utilities also performed significantly better than utilities with
10 other types of regulatory mechanisms, such as lost revenue adjustment mechanisms (LRAMs).
11 Utilities with LRAMs achieving only 0.1% higher savings than utilities with no incentives at
12 all (0.6%). These trends held true when accounting for energy efficiency standards (EERS).
13 States with both EERS and decoupling still reported significantly higher annual energy
14 savings; there was no difference in savings between states with an LRAM or nothing at all,
15 once accounting for the EERS.

16 In addition, the most recent non-Washington reporting on decoupling performance
17 comes from Xcel Energy in Minnesota. After receiving approval in 2015, Xcel reported
18 annual incremental electricity savings of 1.91% for 2016.³⁴ Historically, Xcel has achieved
19 high levels of savings—averaging just under 1.7% since 2010—driven by energy efficiency
20 standards and shared savings incentives, though 2016 savings still reflect a year-over-year

22 ³³ Molina, M., & Kushler, M. (2015). Policies matter: Creating a foundation for an energy-efficient utility
of the future. *ACEEE, Washington, DC*. <http://aceee.org/sites/default/files/policies-matter.pdf>.

23 ³⁴ MN PUC Docket GR-15-826 for Xcel's 2016 Decoupling Annual Report, submitted February 1, 2017.
24 Final 2016 energy savings numbers are drawn from Xcel's 2016 CIP (Conservation Improvement
Program) Report in Docket CIP-12-447.

1 increase. Xcel explicitly noted the role decoupling played in its efficiency performance,
2 stating that decoupling has resulted in positive benefits for both the utility and customers by
3 better aligning organizational priorities, especially as the utility increasingly pursues harder-
4 to-reach customers and savings opportunities.³⁵

5 **Q. What alterations is PSE proposing to its decoupling mechanism?**

6 A. PSE proposes four alterations to its decoupling mechanism.³⁶ First, PSE proposes to
7 include fixed power costs into the decoupling mechanism. In the initial three-year period, PSE's
8 mechanism covered distribution-only costs. Second, PSE proposes to increase the rate test
9 trigger from a 3 percent "soft cap" to a 5 percent "soft cap" for both residential gas customers
10 and all decoupled electric customers. Third, PSE proposes to further disaggregate certain non-
11 residential decoupling rate groups for both its electric and gas services. Lastly, PSE proposes to
12 change the way the company calculates current revenue under the Rate Test. My testimony will
13 only address the first two proposed alterations. I raise no objections to the disaggregation of the
14 decoupling rate groups nor to the calculation of the revenue under the rate test.

15 **Q. How is the company proposing to recover fixed plant costs in this case?**

16 A. The Company is proposing to recover investment-related power plant and transmission
17 costs in the base rates, to which the revenue per customer mechanism will apply. Historically,
18 PSE has recovered both variable and fixed power costs through a separate Power Cost
19 Adjustment Mechanism (PCA).

20 **Q. What concerns do you have with this new inclusion in the company's decoupling**
21 **mechanism?**

22 A. For vertically-integrated utilities that provide both power supply and distribution

23 ³⁵ MN PUC Docket GR-15-826 for Xcel's 2016 Decoupling Annual Report, submitted February 1, 2017.

24 ³⁶ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 126.

1 services, there is the potential for double-recovery of costs if cost adjustment mechanisms are not
2 appropriately designed.³⁷ PSE has a revenue per customer (RPC) decoupling mechanism where
3 allowed revenue grows with customer growth. This is appropriate when only distribution costs
4 are recovered through a decoupling mechanism—as these distribution costs increase with
5 customer count. However, unlike distribution costs, fixed power costs would be expected to
6 remain steady (and decline on a per customer basis as customer count increases) between rate
7 proceedings. Including these fixed plant costs within a RPC approach, with variable power costs
8 recovered in a separate tracking mechanism, can result in over-recovery of some power supply
9 costs.

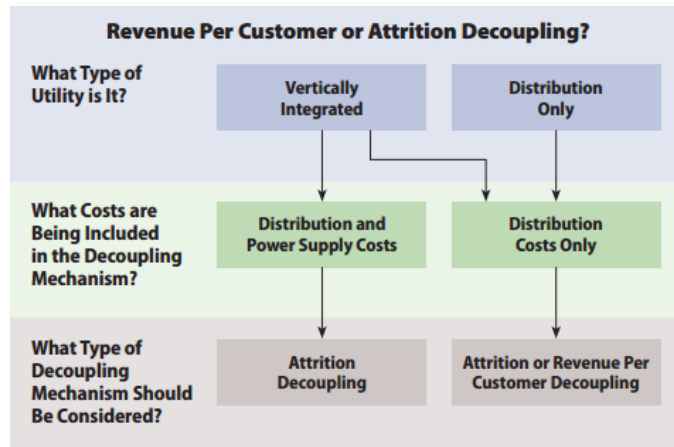
10 When the utility experiences customer growth, the amount it recovers for investment-
11 related power supply costs will also go up if fixed, investment-related power costs are included
12 in an RPC mechanism. However, if the utility meets this customer growth by merely increasing
13 generation at existing plants, selling less power in the wholesale, market or by purchasing power
14 from other parties, the fixed plant costs accounted for in the RPC calculation would not actually
15 be increasing. These increased variable power supply costs (fuel and/or purchased power) to
16 serve customer and load growth would be recovered through the separate PCA mechanism. In
17 this case, the utility would actually double-recover their incremental power supply costs—once
18 through the per-customer decoupling mechanism and then again in the PCA mechanism.

19 **Q. Is this issue addressed in the professional literature relating to decoupling?**

20 A. Yes. In the Regulatory Assistance Project’s recent handbook on customizing decoupling
21
22

23 ³⁷ *Decoupling Case Studies: Revenue Regulation Implementation in Six States*, by Janine Migden-
24 Ostrander, Betty Watson, Dave Lamont, and Richard Sedano, <http://www.raponline.org/wp-content/uploads/2016/05/rap-watsonmigdenostranderlamont-implementingdecoupling-2014-jul.pdf>.

1 for local situations, they address this issue very specifically.³⁸ The “Decoupling Decision Tree”
 2 indicates that for vertically-integrated utilities, either the Commission should approve
 3 distribution-only decoupling (as it has consistently done) or approved distribution and generation
 4 decoupling with an attrition decoupling (not RPC) approach.



11 **Q. Has the Commission addressed this previously?**

12 A. Yes, in both the reopened Cause U-81-41, and again in Docket 011570. In both, the
 13 Parties studied the double-recovery issue, and found that a power cost adjustment that recovers
 14 only variable costs creates a perverse incentive for the Company to meet new resource needs
 15 with purchased power, even if it is more expensive.³⁹ This occurs because the Company
 16 recovers hypothetical and non-existent investment-related costs through base rates even if it
 17 meets load growth with purchased power, and then also recovers the investment-related costs of
 18 the party from which it purchases that power through the PCA mechanism. In both dockets, and
 19 in PSE’s previous decoupling mechanisms, investment-related power and transmission costs
 20

21 ³⁸ Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to*
 22 *Your State’s Priorities*. Montpelier, VT: Regulatory Assistance Project. Available at:
<http://www.raponline.org/knowledge-center/decoupling-design-customizing-revenue-regulation-state-priorities>.

23 ³⁹ For example, see the Direct Testimony of William A. Gaines on Behalf of Puget Sound Energy, Inc.
 24 Regarding Power Cost Adjustment (“PCA”) Mechanism Settlements and the Direct Testimony of Merton R. Lott. Both filed in Docket No. UE-011570 on June 7, 2002.

1 were recovered in the Power Cost mechanism, not in base rates, to avoid this problem.

2 **Q. How does the 2014 settlement stipulation impact the treatment of these fixed plant**
3 **costs?**

4 A. Under the stipulation, PSE agreed to remove the fixed plant costs from the PCA as of
5 January 1, 2017.⁴⁰ Under those terms, only variable costs would still be recovered by the PCA,
6 and PSE would have the ability to petition to have fixed plant costs incorporated into the
7 decoupling mechanism if the pilot was extended.

8 **Q. How would you suggest fixed plant costs be treated and recovered?**

9 A. Below I outline two potential compromise solutions that could help address the issues
10 created by the proposed inclusion of these fixed plant costs issue.

11 First, the Commission and the original parties of the 2015 settlement stipulation could
12 review the appropriateness of the modifications to the PCA approved in the 2015 stipulation. If
13 warranted, the parties and the Commissions could revise the stipulation and once again allow
14 PSE to recover both fixed and variable plant costs under the PCA as provided for in the initial
15 2002 PCA Settlement Stipulation.⁴¹ The Commission and interested parties could also explore a
16 complementary PCA-like mechanism for the timely recovery of these investment-based costs.
17 This mechanism could be tracked and conciliated in a similar fashion and at the same time as the
18 variable cost PCA, but remain more distinct from variable power costs than with the initial 2002
19 PCA Settlement Stipulation.

20 Second, if the above approach is not viable, the Commission and PSE could explore ways
21 to proactively account for and address the potential for over-recovery of fixed plant costs under a

22 ⁴⁰ “2015 Settlement Stipulation,” as referenced in the Direct Testimony and Exhibits of Katherine J.
23 Barnard (KJB-1T), pg. 3.

24 ⁴¹ Direct Testimony of William A. Gaines on Behalf of Puget Sound Energy, Inc. Regarding Power Cost
Adjustment (“PCA”) Mechanism Settlements in Docket No. UE-011570.

1 RPC decoupling mechanism. One potential option would be to incorporate some aspects of an
2 annual attrition adjustment to PSE's current mechanism. PSE could recalculate the fixed power
3 plant costs per customers annually based on the expected average customer count and any cost
4 changes for the applicable year. With this adjustment, in cases where expected customer growth
5 is met with increased generation at existing facilities and changes in purchased power,
6 incremental power supply costs would only be captured in the PCA mechanism. If investment-
7 related power costs remain steady despite customer growth, the RPC amount would decline to
8 ensure no additional recovery of incremental power supply costs through the RPC mechanism.

9 **Q. How is this handled for natural gas, in both current rates and the Company's**
10 **proposed gas decoupling mechanism?**

11 A. For natural gas, there is a clear distinction between distribution costs, recovered through
12 base rates, and all gas supply costs, recovered through the adjustment clause. The gas
13 adjustment clause includes all costs of gas wells, gas transmission, and the natural gas itself. The
14 difference, of course, is that the Company does not own the gas wells, while it does own some
15 (but not all) power plants that provide power or transmission lines that bring power to its service
16 territory. Because the ownership in electricity is split between some owned power plants and
17 transmission, and some purchased power plants and transmission, it is important (as is the case
18 for gas) that these costs be reflected in the power cost adjustment.

19 **Q. What change is the company proposing to the decoupling mechanism rate test**
20 **trigger?**

21 A. PSE proposes to increase the rate test trigger from 3 to 5 percent for residential gas
22 customer and all electric rate classes that are subject to decoupling. In the company's testimony,
23 PSE provides separate reasoning for the gas and electric side.

1 **Q. Why is the company proposing to increase the decoupling mechanism rate test**
2 **trigger from 3 to 5 percent for gas consumers?**

3 A. For gas customers,⁴² PSE notes that gas residential customers have experienced very high
4 levels of unamortized deferred revenues due to mild winters. As noted by witness Jon A.
5 Piliaris, due to Generally Accepted Accounting Principles (GAAP) requirements and the
6 significant deferred balances that have been carried on the residential gas side, PSE “could not
7 recognize \$10.0 million as revenue for CY 2015 even though it was revenue ‘allowed’ for
8 recovery.”⁴³ Mr. Piliaris notes that this situation undermines the effectiveness of the decoupling
9 mechanism on the gas side, as PSE “would welcome higher loads to absorb the decoupling
10 deferrals that the company cannot recognize as current year revenue under GAAP rules.”⁴⁴

11 **Q. Are there alternative approaches PSE could take to address the issue of large**
12 **deferrals rather than raising the rate test trigger?**

13 A. Yes, I believe that this issue could potentially be addressed by PSE reevaluating its
14 weather forecasting methodologies. Improving the weather forecasting methodology will result
15 in more accurate setting of rates that will result in less decoupling adjustments over time and
16 reduce the need for an increase to the rate test trigger.

17 **Q. Do you oppose the company’s request to increase the rate test trigger to 5 percent**
18 **for residential gas customers?**

19 A. Given PSE’s evidential support, at this time I do not oppose the request *for residential*
20 *gas customers* on a temporary basis until the next rate filing where an improvement to weather
21 forecasting can be implemented. PSE has provided concrete proof of financial harm from the

22 _____
⁴² Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 116.

23 ⁴³ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 116.

24 ⁴⁴ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 116.

1 protracted, significant deferrals of costs over and above the 3 percent cap on the gas side. In
2 addition, as the gas deferrals are due to incredibly mild winters, winter heating bills for
3 residential customers are likely lower than historical levels due to low gas usage, and thus,
4 higher surcharges due to the 5 percent trigger have less of a customer bill impact when compared
5 to heating bills for normal winter weather.

6 **Q. Do you have additional recommendations to address the issue of deferrals related to**
7 **warm winters?**

8 A. Yes, I recommend that the Commission direct PSE to review and revise their weather
9 forecasting methodology in their next rate filing. Once a new, improved methodology is
10 established, it seems reasonable to assume that the 3% rate trigger could be reestablished.

11 **Q. Why is the company proposing to increase the decoupling mechanism rate test**
12 **trigger from 3 to 5 percent for electric consumers?**

13 A. Unlike the gas side, PSE notes that there “has not been a significant historic problem with
14 significant unamortized deferred revenue for customers within PSE’s electric decoupling
15 mechanism.”⁴⁵ PSE instead states that, given its proposal to include fixed power costs in its
16 electric decoupling mechanism, it is proactively seeking to increase the rate test trigger on the
17 electric side to prevent similar deferral problems (as seen on the gas side). PSE notes that the
18 inclusion of fixed power costs would roughly double the allowed revenue recovered under the
19 electric decoupling mechanism.⁴⁶ Thus, they conclude that the rate impacts would also likely
20 double compared to previous years.

21 **Q. Do you oppose the company’s request to increase the rate test trigger to 5 percent**
22 **for residential electric customers?**

23 ⁴⁵ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 136.

24 ⁴⁶ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 136.

1 A. Yes. PSE has not provided sufficient reasoning as to why a rate test trigger increase is
2 necessary for electric customers. Given potential adverse impacts of large rate increases on
3 residential consumers, particularly low-income, the Commission should avoid unnecessarily
4 large, single rate increases unless there is clear, substantive proof it is necessary. While PSE
5 claims the increase makes sense given the company's proposal to include fixed power costs,
6 there is little support of this in a historical review of PSE's own mechanism or when reviewing
7 other Washington utilities' mechanisms.

8 According to data provided by Mr. Piliaris,⁴⁷ K-factor revenue for both residential and
9 non-residential electric decoupled groups totaled \$165.5 million between July 2013 and
10 December 2016. By December 2016, monthly incremental K-factor revenue per customer was
11 \$5.33 and \$16.70 for electric residential customers and non-residential customers, respectively.
12 This is around 13-14% of the total monthly RPC for these classes in December 2016.

13 PSE is not requesting the renewal of the K-factor in this case,⁴⁸ which should lower the
14 likelihood of large rate surcharges under the decoupling mechanism, as compared to previous
15 years. Overall, based on a review of the effects of the last rate plan, it is reasonable to conclude
16 that the inclusion of the K-factor had a measurable impact on seen decoupling surcharges, and
17 that the absence of the K-factor in the current proposal will put downward pressure on future
18 surcharges, even if new costs are included in the decoupling mechanism.

19 Without concrete evidence of financial harm due to the rate test trigger level, I oppose
20 PSE's proposal to increase this trigger for electric customers. Given the potential impacts
21 increasing the trigger level on low-income consumers, it is preferable to keep the rate trigger
22 level at the 3 percent cap unless warranted by observed, verified deferral-related issues.

23 ⁴⁷ Exhibit No. ____ (AML-11), PSE Response to Public Counsel Data Request No 062, Attachment A.

24 ⁴⁸ Exhibit No. ____ (AML-12), PSE Response to Public Counsel Data Request No. 060, part (c).

1 VI. SUPPORT FOR LOW INCOME PROGRAM CHANGES

2 **Q. Do you support changes to the low-income program proposed by the Company?**

3 A. Yes. In particular, I support the increase to PSE HELP program funding for electric and
4 natural gas customers and the proposed change in funding allotment between electric and natural
5 gas service as outlined in the direct testimony of Susan Sasville.⁴⁹

6 **Q. On what basis do you support these changes?**

7 A. Ms. Sasville's testimony and related exhibits⁵⁰ demonstrate significant unmet needs
8 among PSE's very low income customers. Her testimony also supports the shift in allocation to
9 80% electric and 20% gas, as justified by recent trends that show this is more in line with the
10 funding needs of the very low income populations. These changes will ensure that more low-
11 income customers are served through the HELP program, helping to alleviate the energy burden
12 on these households. This assistance will have the added benefit of reducing unpaid bills and
13 customer shut-offs, saving related costs that burden PSE and its customers. In addition, I support
14 PSE's decision to continue the higher funding levels for low-income weatherization previously
15 committed to as part of the initial decoupling mechanism (Dockets UE-121697 and UG-
16 121705).⁵¹

17 VII. CONCLUSION

18 **Q. Does this conclude your testimony?**

19 A. Yes.
20
21

22 ⁴⁹ Direct Testimony and Exhibits of Suzanne M. Sasville (SMS-1T), pg. 4.

23 ⁵⁰ Direct Testimony and Exhibits of Suzanne M. Sasville, Exhibit No. ____ (SMS-3), which indicates 20%
of households live at or below 150% of the federal poverty line.

24 ⁵¹ Direct Testimony and Exhibits of Jon A. Piliaris (JAP-1T), pg. 149.