

**BEFORE THE WASHINGTON
UTILITIES & TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

v.

PACIFIC POWER & LIGHT COMPANY

DOCKET UE-161204

RESPONSIVE TESTIMONY OF KATHLEEN A. KELLY (KAK-1T)

ON BEHALF OF

WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL,
PUBLIC COUNSEL UNIT

APRIL 21, 2017

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EXHIBITS LIST

| | |
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| Exhibit KAK-2 | Resume of Kathleen A. Kelly, Daymark Energy Advisors, Inc. |
| Exhibit KAK-3 | Summary of Expert Witness Testimony |
| Exhibit KAK-4 | Direct Testimony of Jon A. Piliaris, Docket UE-161123, Exhibit No. JAP-1CT (Redacted) |
| Exhibit KAK-5 | Pacific Power Response to Public Counsel Data Request No. 9 |
| Exhibit KAK-6 | Pacific Power Response to CREA Data Request No. 39 |
| Exhibit KAK-7 | Pacific Power Response to Boise White Paper Data Request No. 34 (Attachments consists of six workbooks, which are provided electronically only and as provided by Pacific Power) |
| Exhibit KAK-8 | Pacific Power Response to Boise White Paper Data Request No. 56 |
| Exhibit KAK-9 | Functional Breakdown of Non-Net Power Cost Revenue Requirement by Customer Class based on Cost of Service Study |
| Exhibit KAK-10 | Pacific Power Response to Boise White Paper Data Request No. 54 |
| Exhibit KAK-11 | Pacific Power Response to Boise White Paper Data Request No. 55 |
| Exhibit KAK-12 | Pacific Power Response to Boise White Paper Data Request No. 1 |
| Exhibit KAK-13 | Pacific Power Response to Public Counsel Data Request No. 16 |
| Exhibit KAK-14 | CREA Response to Public Counsel Data Request No. 3 (including Attachment A) |
| Exhibit KAK-15 | CREA Response to Public Counsel Data Request No. 1; CREA Response to Pacific Power Data Request No. 18 |
| Exhibit KAK-16 | Pacific Power Response to WUTC Staff Data Request No. 4 (with Attachment to WUTC-4) |
| Exhibit KAK-17 | Yakama Power Response to Public Counsel Data Request No. 1 |
| Exhibit KAK-18 | CREA Response to Pacific Power Data Request No. 12 |

1 **I. INTRODUCTION**

2 **Q: Please state your name and business address.**

3 A: My name is Kathleen A. Kelly, and my business address is One Washington Mall, Boston,
4 Massachusetts, 02108.

5 **Q: By whom are you employed and in what capacity**

6 A: I am employed as Vice President and Principal Consultant for Daymark Energy Advisors, Inc.
7 (Daymark).

8 **Q: Please describe your professional qualifications.**

9 A: I am a utility industry specialist with 40 years of experience in areas that include retail
10 industry restructuring issues such as customer equity and risks of recovery, utility rate
11 design, and I have advised utilities with regard to efficiency in operations and business
12 practices. I received my Master of Business Administration (MBA) from Northeastern
13 University and a Bachelor of Science (BS) degree in Mathematics from the University of
14 Massachusetts. Since joining Daymark in February of 2016, I have worked on projects
15 related to mergers and acquisitions, investments in energy infrastructure, energy markets,
16 regulatory policy, and rate cases. Prior to joining Daymark, I worked at Lummus
17 Consultants International, Inc. which was formerly known as Stone & Webster Management
18 Consultants, leading a practice in utility management and planning. In this role I advised
19 utilities, developers, large customer groups, and regulators with regard to utility business
20 and resource planning, management and operations, with particular regard to evaluating
21 regulatory strategy, acquisitions, and business operational efficiencies. Throughout my
22 career, I have gained and demonstrated considerable experience and expertise in many

1 utility-related matters. My resume is provided as Exhibit No. KAK-2, and a summary of my
2 testimony experience is contained in Exhibit No. KAK-3.

3 **Q: Please describe Daymark Energy Advisors, Inc. and its business.**

4 A: Daymark Energy Advisors is the new name of the firm formerly known as La Capra
5 Associates. The name change occurred on November 9, 2015. Daymark provides
6 consulting services in energy planning, market analysis, and regulatory policy in the
7 electricity and natural gas industries. We serve a national and international clientele from
8 our offices in Boston, Massachusetts, and Portland, Maine, providing consulting services to
9 a broad range of organizations involved with energy markets, including renewable energy
10 producers, private and public utilities, transmission owners, energy producers and traders,
11 energy consumers and consumer advocates, regulatory agencies, and public policy and
12 energy research organizations. Our technical skills include power market forecasting
13 models and methods, economics, management, planning, rates and pricing, energy
14 procurement and contracting, and reliability assessments. Our experience includes detailed
15 analyses of energy and environmental performance of the electric systems, economic
16 planning for transmission and distribution, and market analytics.

17 **Q: Have you previously testified before the Washington Utilities and Transportation**
18 **Commission (“Commission”)?**

19 A: No.

20 **Q: On whose behalf are you testifying in this proceeding?**

21 A: I am testifying on behalf of the Washington State Office of the Attorney General, Public
22 Counsel Unit (“Public Counsel”).

1 **II. PURPOSE OF TESTIMONY AND SCOPE OF REVIEW**

2 **Q: What is the purpose of your testimony?**

3 A: Daymark Energy Advisors has been retained to review Pacific Power & Light Company’s
4 (“Pacific Power” or “Company”) proposed revisions to the permanent disconnection and
5 removal tariffs for electric service. The purpose of these revisions is to modify Rule 6 to
6 provide two options for customers who decide to obtain service from a different provider
7 and permanently disconnect from Pacific Power’s system and to establish a Stranded Cost
8 Recovery Fee in Schedule 300. The Company contends that its current effective tariffs do
9 not adequately address the sale of electric facilities and the associated transfer of liability,
10 nor do they allow for cost shifting mitigation and the proper recovery of stranded costs.
11 Therefore, the Company has recommended that departing customers have the option to
12 either purchase certain electric facilities (“Option One”) or pay to have those removed
13 (“Option Two”), as well as requiring these customers to pay a Stranded Cost Recovery Fee.

14 **Q: Please describe the scope of your review of the Company’s proposed revisions to Rule 6**
15 **and Schedule 300.**

16 A: My review of the proposed changes to Rule 6 and Schedule 300 in this testimony is focused
17 on five issues:

- 18 1) Whether the proposed Stranded Cost Recovery Fee is fair and equitable to both
19 customers who choose to disconnect and take service from another provider and the
20 Company’s remaining customers;
- 21 2) Whether the proposed additions of Option One and Option Two under Rule 6 are fair
22 and equitable to both Pacific Power and departing customers;
- 23 3) Whether the proposed tariff change should apply to all customer classes at this time,

1 including residential customers;

2 4) Whether the departure of existing customers who choose to take service from
3 another provider creates a safety concern; and

4 5) Whether the Company's continued operation as the service provider to existing
5 customers located in the counties of Columbia and Walla Walla while remaining
6 subject to loss of load to competitive providers erodes the generally accepted notion
7 of a regulatory compact between the state and the utility.

8 **III. BACKGROUND**

9 **Q: Please briefly describe the circumstances that have motivated the Company to propose**
10 **changes to its tariff in this proceeding.**

11 A: Prior to 1999, the Company had an informal agreement with the Columbia Rural Electric
12 Association ("CREA") under which the utility whose facilities were located closest to a
13 customer would serve that customer.¹ In 1999, the Company received approval of its
14 original net removal tariff, and since the original net removal tariff went into effect,
15 additional customers have requested permanent disconnection. According to Pacific Power,
16 the continued demand for disconnection has created the potential for duplicative facilities at
17 the same customer location and may lead to stranded costs for which recovery is either at
18 risk or must be recovered from the Company's remaining customers.

19 The most recent instance of permanent disconnection was reviewed by the
20 Commission in Docket UE-143932, *Walla Walla Country Club v. Pacific Power*. In that
21 docket, Walla Walla Country Club requested the Commission to require Pacific Power to
22 disconnect its facilities from the Club's property under the terms of the Company's Net

¹ Direct Testimony of R. Bryce Dalley, Exhibit No. RBD-1T at 4:11-19.

1 Removal Tariff, Rule 6. The Club disputed the Company's requirement that certain
2 facilities be included in the cost of removal under Rule 6. The Commission's final order in
3 UE-143932 clarified that the Company may charge the Club for the disputed facilities only
4 if a safety or operational reason exists to justify their removal.² Pacific Power's proposal in
5 the current docket addresses changes to the tariff needed in response to the Commission's
6 clarification in Docket UE-143932.

7 IV. PROPOSED TARIFF REVISION

8 **Q: Please briefly describe the proposed revisions to its current tariff?**

9 A: The Company has proposed revisions to its tariff to be applicable to future requests by any
10 customer requesting permanent disconnection. These revisions amend Rule 6, General
11 Rules and Regulations – Facilities on Customers' Premises, and add definitions for related
12 key terms used in Rule 6 to Rule 1, General Rules and Regulations - Definitions.³

13 The proposed revisions to Rule 6 expand the procedure for requesting permanent
14 disconnection. Rule 6, Section I, Permanent Disconnection and Removal of Company
15 Facilities, now includes two options to purchase and transfer liability for facilities or to pay
16 for removal of facilities, and establishes the Company's right to assess a Fair Market Value
17 for facilities abandoned in lieu of removal or purchase, as well as to assess a Stranded Cost
18 Recovery Fee.⁴

19 The Company also amends Schedule 300, whose purpose is to list all the service
20 charges defined in the General Rules and Regulations, to reflect the newly defined Stranded

² *Walla Walla Country Club v. Pac. Power & Light Co.*, Docket UE-143932, Order 05, Final Order Denying Petition for Review; Clarifying Order 03 ¶ 8 (May 5, 2016).

³ Pacific Power Tariff WN U-75, Rule 1, Sheet Nos. R1.1 through R1.3 [Version with track changes. Definitions added besides Stranded Cost Recovery Fee include Actual Cost of Removal (including costs to investigate redundant services), Facilities, Fair Market Value, Net Book Value, and Salvage].

⁴ *Id.*, Rule 6, Sheet No. R6.2 – R6.3, Section I.

1 Cost Recovery Fee for Residential and Non-Residential Customers proposed in Rule 6.⁵

2 The revised Schedule 300 also replaces a low flat fee (\$200 - \$400) as the rate for the
3 removal of facilities with the formula actual cost less salvage.⁶

4 **Q: Do you agree that the Company is required to propose a revision to their existing**
5 **tariff?**

6 A: The Company has proposed revisions to its existing tariff in response to the Commission
7 order it received in Docket UE-143932 and to address the missing elements of a Stranded
8 Cost Recovery Fee summarized above. I conclude, for reasons discussed in more detail
9 below, that the Company's proposal may allow it to recover costs for more facilities than
10 necessary, and the Company does not provide sufficient rationale for all the facilities it
11 proposes to include in its definition of costs that would be impacted by a departing
12 customer. Furthermore, the Company excluded consideration of lost contribution to low-
13 income rate assistance and energy-efficiency programs. As a result, the Company has not
14 presented sufficient evidence to support its proposed tariff revision and should be required to
15 do so before receiving Commission approval.

16 **Q: Please describe how Rule 6 works in the current tariff.**

17 A: Currently, Rule 6 stipulates that a customer who requests permanent disconnection from
18 Pacific Power's system must pay the Company the actual cost for removal less salvage of
19 those facilities that require removal for safety or operational reasons. In the Company's
20 view, the term "facilities" is defined as "electric infrastructure designed, built, and installed
21 to provide service, including but not limited to transmission and distribution lines, service
22 drops, transformers, poles, risers, conduit, vaults, and any other equipment used to supply

⁵ *Id.*, Schedule 300, Sheet No. 300-1.

⁶ *Id.*, Schedule 300, Sheet No. 300-1.

1 electricity.”⁷ Pacific Power is responsible for providing an estimate of the cost of facility
2 removal before work commences. The departing customer is required to pay the estimated
3 amount before they are disconnected and facilities are removed. The Company is also
4 required to determine the actual cost of removal, less salvage, and provide either an invoice
5 for extra costs or a refund for overpayment.

6 **Q: Please explain how the proposed revisions to Rule 6 expand the procedure to request**
7 **permanent disconnection and removal of facilities.**

8 A: The Company argues that Rule 6 in its current form does not correctly characterize recent
9 disconnection and removal conditions, nor does it explicitly consider the sale of facilities.
10 The Company proposes to expand the definition of the basis for disconnection and removal
11 to include instances when the customer chooses to be served by another utility or obtains
12 redundant service from another provider. The Company is also seeking approval to require
13 customers interested in the removal of facilities to pay the actual cost of removal, which are
14 defined as “all removal costs, including, but not limited to labor costs, contractor costs, costs
15 to investigate redundant services, and Net Book Value of Facilities less Salvage.”⁸ This
16 option (“Option One”) requires the departing customer to pay an estimate of the actual cost
17 of removal before permanent disconnection and facility removal.

18 The Company proposes a second option (“Option Two”) that specifically allows for
19 the purchase of underground conduit and vaults at “Fair Market Value in lieu of removal”
20 and for customers to “pay Actual Cost of Removal of all Facilities not sold.”⁹ As with
21 Option One, the Company will provide an estimate of the appropriate charges for payment

⁷ *Id.*, Rule 1, Sheet No. R1.2.

⁸ *Id.*, Rule 1, Sheet No. R1.1.

⁹ *Id.*, Rule 6, Sheet No. R6.3, Section I.1.b.

1 by the customer before the permanent disconnection and removal of any facility.¹⁰

2 **Q: Does the proposed expansion of Rule 6 afford the Company additional discretion not**
3 **present in the current Rule 6?**

4 A: Yes, the proposed revision to Rule 6 procedures allows the Company additional discretion in
5 three ways.

6 First, the Company requests that in lieu of removal or purchase by the departing
7 customer, it be allowed to abandon in place some or all facilities if, “in the Company’s sole
8 discretion, service may be negatively impacted or safety issues may arise as a result of
9 removal or purchase by the departing customer.”¹¹ The Company states that it will be
10 responsible for decommissioning and leaving in place these facilities in “a safe manner
11 consistent with best industry practices.”¹²

12 Second, the facilities open to removal may now be those located in “right of ways,
13 private property, or any other property used to provide the departing customer electric
14 service.”¹³ This provision applies to the Company’s discretion to mark facilities for removal
15 for safety reasons, not just for those facilities that departing customers pay to have removed
16 at their place of residence or business.¹⁴

17 The third discretionary assessment, and potentially the one with the greatest financial

¹⁰ *Id.*, Rule 6, Sheet No. R6.3, Section I.1.b

¹¹ *Id.*, Rule 6, Sheet No. R6.3, Section I.2.

¹² *Id.*

¹³ *Id.*, Rule 1, Sheet No. R1.2, Permanent Disconnection and Removal definition.

¹⁴ *Id.*, Rule 6, Sheet No. R6.3, Section I.3. The Company’s revision does not affirmatively state that the departing customer would pay for facilities designated for removal from right of ways. Instead this provision to Section 1.3 states, “No later than 90 days after removal of Facilities not purchased by the departing Customer or not abandoned and decommissioned by the Company, the Company will determine the Actual Cost of Removal and adjust the estimated bill to that amount.” This adjustment could be due to a revision in the estimated cost of the Facilities purchased by the departing Customer or additional facilities in right of ways. Because the Company has afforded itself sole discretion to determine such costs, it is more conservative to assume that the departing Customer will be responsible for paying for Facilities in both categories.

1 impact, is the Company's requirement that departing customers pay a Stranded Cost
2 Recovery Fee before facilities are disconnected.¹⁵ Pacific Power's proposed change to
3 Schedule 300 explicitly lists the proposed Stranded Cost Recovery Fees for Residential and
4 Non-residential customers (including irrigation customers).¹⁶ This fee is in addition to the
5 cost of each customer's selection of either Option 1 or Option 2 to compensate the Company
6 for direct infrastructure removal, abandonment, or sale.

7 **Q: Does the proposed revision to Rule 6 account for the transfer of liability for the**
8 **facilities that have been abandoned in place?**

9 A: The revision to Rule 6 specifically states that the departing customer will "assume all
10 responsibility and liability associated with purchased underground conduit and vaults at the
11 time of disconnection (and with) abandoned and decommissioned Facilities at the time of
12 disconnection."¹⁷ This effectively transfers the liability for the facilities abandoned in place
13 to the departing customer.

14 **Q: How does the proposed revision to Rule 6 adjust the estimated amount collected from**
15 **departing customers to reflect actual costs and allocate that revenue to remaining**
16 **customers?**

17 A: Under both Option One and Option Two, customers must pay an estimated amount provided
18 by the Company before the permanent disconnection and removal of any facility.
19 Customers who are tenants must obtain a notarized affidavit of the owner's permission for
20 permanently disconnection and removal of facilities. PacifiCorp proposes to increase the
21 time in which PacifiCorp must notify customers of adjustments to the estimated bill to

¹⁵ *Id.*, Rule 6, Sheet No. R6.3, Section I.4.

¹⁶ *Id.*, Schedule 300, Sheet No. 300.1.

¹⁷ *Id.*, Rule 6, Sheet No. R6.3, Section I.2.

1 reflect the actual cost of removal from 60 days to 90 days.¹⁸

2 **Q: What is the Company proposing to do with the proceeds of payments from departing**
3 **customers resulting from Options One and Two?**

4 With respect to both Option One and Option Two, the net proceeds are treated as proceeds
5 of utility property and are allocated to remaining ratepayers to reflect the risk of ownership
6 that ratepayers bear.¹⁹ The Company has proposed to track the fees collected by rate
7 schedule and deposit them in the deferral account set up under their decoupling
8 mechanism.²⁰ This proposal suggests some type of true-up mechanism will be required in a
9 compliance filing to show that the estimated fees collected and later changed due to
10 adjustment to actuals are flowing through accurately using the decoupling mechanism. In
11 this filing, the Company does not address whether it will accrue interest on the outstanding
12 balance of fees collected between the time of collection and the time these fees are credited
13 back to customers.

14 **Q: Are the proposed options for permanent disconnection and removal fair and equitable**
15 **to both departing and remaining customers?**

16 A: In the absence of a franchise agreement, Pacific Power should have a means by which their
17 existing customers are protected from the rate impacts of competitive customer departures to
18 a new provider. This proposed tariff change expands the recovery from departing customers
19 and offers two ways of establishing the amount to be recovered. Options 1 and 2 provide
20 definition and recovery of stranded infrastructure investment and each option provides a
21 valid approach for establishing the cost of a permanent customer departure rather than

¹⁸ *Id.*, Rule 6, Sheet No. R6.3, Section I.3.

¹⁹ This revision is consistent with the proposed stranded cost recovery fee allocation methodology in Docket UE-161123, as cited in this docket in Dalley, Exhibit No. RBD-1T at 7:13-16.

²⁰ Dalley, Exhibit No. RBD-1T at 16:12-14.

1 recovering that cost from its remaining customers. Option 1 is a standard engineering and
2 accounting definition of the costs. With Option 2, however, a Fair Market Value should be
3 set by an independent party, rather than by the Company.

4 **Q: Why do you disagree with allowing the Company sole discretion to establish Fair**
5 **Market Value as the basis for the value of facilities under Options 1 and 2?**

6 A: Establishing Fair Market Value requires knowledge of the numerous approaches involved,
7 such as the discounted cash flow income method, comparable sales, and net book, and using
8 an independent third-party appraiser is the preferred approach. With a broader definition of
9 the infrastructure impacted by a customer departure, the Company has established
10 appropriate recovery of their now-stranded direct infrastructure investment, but it raises the
11 possibility that the Company will recover costs for the same facilities twice, and it may be
12 incompatible with Commission determination in other orders.²¹ In any event, if an
13 independent appraiser is not required, it is important to make sure that individual customers
14 have the option to submit complaints to the Commission, should they disagree with Pacific
15 Power's application of the tariff for resolution on an individual basis.

16 Pacific Power has also incorporated a second revenue recovery fee that is additive to
17 either Option 1 or 2 in the Stranded Cost Recovery Fee. I discuss that in the next section of
18 my testimony.

²¹ See, *In re: Puget Sound Energy for an Accounting Order Approving the Allocation of Proceeds of the Sale of Certain Assets to Pub. Util. Dist. #1 of Jefferson Cty.*, Docket UE-132027, Order 04 ¶ 42 (Sept. 11, 2004), which states:

PSE would have us return to use of the much criticized and long discredited "fair value" or "fair market value" approach. This is an appropriate concept of value in the context of a condemnation proceeding and, in fact, the measure of what a seller is entitled to receive when a municipality, PUD, or other public entity exercises its power of eminent domain. It is not an appropriate concept of value in the context of applying appropriate regulatory treatment to utility property that is subject to rate base rate of return regulation. (Footnote omitted.)

1 **V. STRANDED COST: DEFINITION AND EXAMPLES**

2 **Q: What is Pacific Power’s proposal relative to its stranded cost recovery fee?**

3 A: Pacific Power’s stated purpose for proposing a Stranded Cost Recovery Fee is to lessen the
4 financial impact to remaining customers after a customer decides to permanently disconnect
5 and switch to a new service provider.²² The Company indicates that the Stranded Cost
6 Recovery Fee is intended to mitigate cost shifting and enable the Company to recover
7 stranded costs associated with the departure of customers seeking service from another
8 provider. The Company stated that it designs its system and resource investments to ensure
9 reliable service based on the entire community of customers. To capture the costs associated
10 with resource investments made to serve the customers leaving the system, Pacific Power
11 proposes to charge departing customers a Stranded Cost Recovery Fee before they
12 permanently disconnect service.

13 In this section, I define stranded costs in the utility industry and provide examples of
14 how to establish an estimate of stranded costs. In the next section, I detail the Company’s
15 proposal and then summarize what that proposal’s impact is on customers and whether it is
16 appropriate as proposed.

17 **Q: What is a “stranded cost?”**

18 A: There are many potential definitions of the term “stranded cost.” In essence, a utility asset is
19 said to be “stranded” if it is no longer used and useful prior to the end of its typical useful
20 life. As a simple example, if a utility invests significant capital in emissions control systems
21 in an old coal facility, but five years later finds it must retire the plant based on economics
22 due to changing market conditions—such as reductions in renewable technology costs—the

²² Dalley, Exhibit No. RBD-1T at 9:14-18.

1 emissions control system becomes a significant stranded asset. Utility planners expected the
2 system to last much longer than five years and be depreciated and financed over that time.
3 Instead, it is retired after only five years, leaving a significant undepreciated plant balance
4 on the utility's books. The term "stranded cost" often refers to such undepreciated plant
5 balance and debt obligations left on a utility's books for stranded assets. Regulators may
6 still approve recovery of such stranded costs from ratepayers even though stranded assets are
7 no longer used and useful as long as the regulator finds the utility did not act imprudently in
8 its investments.

9 **Q: Are there other circumstances that can create stranded costs for utilities?**

10 **A:** Yes, there are four major categories of circumstances that can give rise to stranded assets.

11 Stranded costs arise when:

12 1) Consumers are given access to competitive markets and utilities are no longer
13 allowed to be vertically integrated and must divest their ownership positions in
14 jurisdictional power plants. Restructuring requires utilities to sell generation assets
15 to third parties who then operate the facilities and sell the output either directly to
16 consumers or indirectly through marketers who ultimately have the customer
17 relationship. In many states, when restructuring went into effect, the market price
18 for generation assets was often less than the undepreciated plant balance—also called
19 the net book value—that a utility would have been entitled to recover under
20 traditional Cost of Service ("COS") ratemaking. The difference between the two—
21 that is between the market price and the net book value of the asset—is often termed
22 a "stranded cost," although it is not associated with a stranded asset.

23 2) Cities, towns or counties decide to establish municipal utilities that are owned by

1 customers. These municipal utilities may purchase the assets of existing utilities at a
2 price that gives rise to stranded costs for the seller. For example, Pacific Power is
3 involved in a case in Oregon where the city of Millersburg initiated studies in 2014
4 to assess the feasibility of forming a municipal utility district. In that case, Pacific
5 Power noted that the city of Las Cruces, New Mexico abandoned its efforts in 2000
6 to create a municipal electric utility due to the burden of having to pay stranded costs
7 to El Paso Electric.²³

- 8 3) Customers decide to build and operate an on-system generating unit or enter into a
9 direct purchase agreement with another generator and use the local utility's
10 transmission and distribution facilities to wheel the power to their own campus,
11 thereby reducing but not eliminating the customer's requirement from the utility and
12 remaining distribution customers. This category includes customers who build
13 cogeneration units to meet process load requirements (e.g. central heating plants at
14 airports, universities, wastewater treatment plants, and other manufacturing plants.)
15 These customers may be able to operate as an island but still remain connected to the
16 utility's distribution system for reliability. Adoption by commissions in various
17 jurisdictions of programs to incent development of renewables and distributed
18 generation through feed-in tariffs can have a similar impact on existing utilities. For
19 example, Hawaii²⁴ and New Hampshire²⁵ are both jurisdictions where net metering

²³ Press Release, Pacific Power, "Pacific Power calls on Millersburg to fully disclose millions in stranded costs tied to MUD formation," (Sept. 16, 2014), https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/In_the_Community/Pacific%20Power%209-16-14%20Millersburg%20stranded%20cost%20release.pdf.

²⁴ *In re: P.U.C. Instituting a Proceeding to Investigate Distributed Energy Res. Policies*, Haw. P.U.C. Docket No. 2014-0192.

²⁵ *Elec. Dist. Utils. – Dev. Of New Alt. Net Metering Tariffs and N.H. Pub. Serv. Comm'n NEM Proceeding*, Docket No. DE 16-576.

1 is being evaluated in order to ensure appropriate treatment of renewables and
2 distributed generation.

3 4) Existing franchise agreements expire without being successfully renegotiated, or do
4 not exist, resulting in multiple providers building distribution facilities to compete
5 for customers at the street level. As customers switch to the successful bidder, the
6 distribution facilities installed by the former supplier become redundant. (For
7 example, as recently as 1986, more than one Pennsylvania natural gas utility was
8 allowed to provide service in certain townships²⁶ and separately certain utilities were
9 required to replace farm taps²⁷ served by intrastate pipelines with their own
10 distribution systems.²⁸) Franchise agreements provide, in return for a fee, an
11 exclusive right to distribute energy to customers located within municipal geographic
12 boundaries by allowing only one utility to build and operate distribution facilities
13 within municipal rights of way.

14 **Q: What are the minimum conditions that give rise to stranded costs for utilities?**

15 **A:** For there to be stranded costs in these cases, the following must be true:

- 16 • The costs will not be avoided once the departing customer leaves the system. This
17 implies the cost is a “fixed cost”—such as the depreciation and financing cost of
18 utility plant already in the ground. Such costs do not vary with the amount of load
19 served by the utility. “Variable costs” that do vary with load—such as fuel costs—
20 are typically avoidable and therefore not stranded with a customer’s departure.

²⁶ See, *People’s Nat. Gas v. Pa. P.U.C.*, Docket No. 2241 C.D. 1987, available at:

<https://www.courtlistener.com/opinion/2101898/peoples-nat-gas-co-v-pa-puc/>.

²⁷ Definition of Farm Tap suggesting farm taps may be considered part of either a transmission or a gas utility distribution system: <https://viadata.wordpress.com/2011/05/26/farm-taps-clarification-for-dimp-%C2%A7192-1003/>.

²⁸ *Pa. P.U.C. v. Peoples TWP*, Pa. P.U.C. Docket No. R-2014-2399598, 1307(f) Purchased Gas Cost, Statement No. 2 at 38 (Jan. 31, 2014).

- 1 • Additional market revenues obtained in the wholesale market caused by the
2 customer’s departure, that do not fully compensate the utility for revenue the
3 departing customer would have paid for fixed costs if it had remained on the system,
4 may be identified as stranded costs for some defined period of time.

5 **Q: Have utility stranded costs been recognized as an issue for utilities within Washington**
6 **State?**

7 A: The Commission recognized the existence of stranded costs generally in Dockets
8 UE-001952 and UE-001959 (consolidated) when it stated:

9 [i]n general, the term refers to costs a company with a *de jure* or *de facto*
10 monopoly in a particular service territory prudently incurs and is ordinarily
11 allowed to recover under traditional forms of utility regulation, but that may
12 become unrecoverable if the industry is deregulated so that the utility’s
13 historic customers are given access to competitive markets.²⁹

14 The current filing is an example of stranded costs arising in the absence of a franchise
15 agreement between Pacific Power and the counties of Columbia and Walla Walla.

16 However, it also arises from a different kind of “stranded cost,” namely costs incurred to
17 serve an individual customer that has left the system to take service from a neighboring
18 utility. This situation is relatively unusual in U.S. electric markets because utilities typically
19 have exclusive service territories by law. Washington State does not.

20 **Q: As a general matter, how are stranded costs quantified?**

21 A: Quantifying the cost of a stranded asset is usually straightforward, as a utility will have
22 records of the asset’s cost and resulting net book value to be recovered. However,
23 quantifying an asset’s stranded costs which are impacted by restructuring is more

²⁹ *Air Liquide Am. Corp. v. Puget Sound Energy, In re: Petition of Puget Sound Energy for an Order Reallocating Lost Revenues Related to any Reduction in the Schedule 48 or G-P Special Contract Rates*, Dockets UE-001952 & UE-001959 (Consolidated), Eleventh Supplemental Order 14 n.8 (Apr. 5, 2001).

1 complicated. Under restructuring, assets are still in use, so the stranded cost is not the entire
2 net book value of any asset. Instead, the stranded cost is equal to the net book value minus
3 the market value. Quantifying an asset's market value can be difficult. Such a value
4 depends on the market rules and competition from other market participants. In some
5 jurisdictions, utilities divested assets to help quantify stranded costs for purposes of cost
6 recovery after restructuring.³⁰ The divestiture would result in a sale price to serve as the
7 market value of the asset.

8 For stranded costs in cases such as this, when there are no specific stranded assets
9 being retired or assets being sold,³¹ quantifying stranded costs is very difficult. The utility
10 must quantify the fixed costs of serving the departing customer and net out any additional
11 market revenues that may contribute to recovering such fixed costs. Identifying fixed costs
12 attributable to any one customer is complicated given the highly-networked nature of utility
13 electric service. The potential for additional market revenues also varies depending on
14 market conditions, which are uncertain. I discuss these issues in more detail below.

15 **A. Determining Fixed Costs.**

16 **Q: How does a utility determine the fixed costs of serving a particular customer?**

17 A: There is no one generally accepted way to estimate fixed costs of serving a specific
18 customer. Nonetheless, here are some generally accepted approaches:

- 19 • **Engineering analysis:** A utility could perform an engineering analysis to assess
20 what specific assets are used to serve a customer. This could involve utility planners

³⁰ William D. Liggett et al. Energy Info. Admin., THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY 2000: AN UPDATE, at 106 (2000), http://webapp1.dlib.indiana.edu/virtual_disk_library/index.cgi/4265704/FID1578/pdf/electric/056200.pdf.

³¹ Per the proposed tariff, there could be distribution assets in place to serve the customer that are sold or retired, but the proposed Stranded Cost Recovery Fee in this proceeding is not directly related to such assets.

1 assessing how they would change system design—such as the size of a substation—
2 if a customer were no longer being served by the utility. Planners could run models
3 to see how generation dispatch and system power flows through the transmission and
4 distribution system would change as a result of a customer taking service from
5 another utility. The net book value of the assets that changed in their utilization
6 could then theoretically be allocated to the customer on a load ratio share basis as an
7 estimate of fixed costs.

- 8 • **Direct categorization:** Under this method, a utility would analyze the COS for a
9 particular customer or customer class and categorize all the costs assigned or
10 allocated to that customer or class as fixed or variable based on the type of cost
11 incurred and expert judgement. For instance, a fuel cost would be a variable cost,
12 but depreciation would be a fixed cost.
- 13 • **Planning & Financial models:** Planners could run models to estimate total revenue
14 requirements with and without the customer as part of the utility’s system. All costs
15 not avoided by the customer’s departure would be considered fixed costs.
- 16 • **Cost allocation methods:** Utilities could categorize costs as fixed or variable based
17 on how such costs are allocated to rate classes within its COS model. For instance,
18 only costs allocated by demand or customer allocators could be considered fixed
19 costs. (Allocation by demand is consistent with the Peak Credit method discussed
20 below.)

21 **Q: Please summarize pros and cons of each approach.**

22 **A:** The table below summarizes general pros and cons of these approaches.

1
 2

Table 1: Summary of pros and cons of various methods of estimating fixed costs of serving a particular customer.

| | | |
|-------------------------------|-------|---|
| Engineering Analysis | PROS: | <ul style="list-style-type: none"> Identifies specific assets with net book values that can be quantified |
| | CONS: | <ul style="list-style-type: none"> Networked and complex nature of power grid complicate the analysis³² Assets can be “lumpy” in size,³³ such that if the size of the departing customer is small compared to the size of the assets under consideration, an engineer may not reasonably be able to detect a change in design Does not consider customer service or administrative and general costs |
| Direct Categorization | PROS: | <ul style="list-style-type: none"> Simple to calculate Considers all costs Easy to understand |
| | CONS: | <ul style="list-style-type: none"> The fixed nature of a cost depends on time period under consideration; given a long enough time horizon, no cost is fixed (discussed in more detail below) Different experts may disagree on which costs to consider as fixed or variable |
| Planning and Financial Models | PROS: | <ul style="list-style-type: none"> Comprehensive-considers all costs Also provides quantification of changes in market revenues (discussed more in following section of the testimony) |
| | CONS: | <ul style="list-style-type: none"> Time-intensive and costly to run models, especially over long-term horizon Limitations on model algorithms may not detect any difference in costs if the departing customer is small compared to the rest of the system (also discussed in next section) Future is uncertain, and it may be difficult to true-up actual stranded costs to those predicted by the models |

³² Changing modeling assumptions such as fuel prices, load in other areas, contingencies such as forced generation outages, and many others could all change the results of the analysis. This means different generation assets would experience dispatch changes or different transmission assets would experience different power flows with and without the departing customer.

³³ Generation and transmission assets are typically sized in 10MW or 100MW or even larger size increments. Distribution assets can be sized in smaller increments, but still larger than the order of magnitude of a small customer with 1 kW of demand.

| | | |
|-----------------|-------|---|
| Cost Allocation | PROS: | <ul style="list-style-type: none"> • Relies on cost allocation already approved by regulators • Considers all costs |
| | CONS: | <ul style="list-style-type: none"> • Cost causation principles that underlie cost allocation decisions consider far more than the fixed and variable nature of the costs • Cost allocation of the cost of depreciation and financing of generation plant is typically controversial in cost allocation proceedings, meaning experts disagree over how to fairly allocate such costs even though they are typically considered “fixed costs” |

1

2 **Q: Have other utilities in Washington used other methods to quantify fixed costs of**
 3 **servicing a customer?**

4 A: Yes. Recently, Puget Sound Energy (PSE) filed for approval of a tariff that would allow it
 5 to recover stranded costs from large commercial/industrial customers who choose to
 6 purchase power supply from an alternative provider.³⁴ In its initial filing, PSE presented
 7 results of three different methods of estimating stranded costs that would form the basis of
 8 an exit fee for the large commercial customer.³⁵ The methods were:

- 9 • Peak Credit Method;
- 10 • Proposed Approach; and
- 11 • Fixed Power Cost Adjustment (PCA) Costs Method.

12 **Q: Please briefly describe PSE’s Peak Credit method and its pros and cons for estimating**
 13 **fixed costs.**

14 A: PSE’s Peak Credit method is a cost allocation-type method, which classifies power costs
 15 allocated on the basis of demand as fixed and power costs allocated on the basis of energy as

³⁴ *Wash. Utils. & Transp. Comm’n v. Puget Sound Energy*, Docket UE-161123.

³⁵ Exhibit No. KAK-4, *Wash. Utils. & Transp. Comm’n v. Puget Sound Energy*, Docket UE-161123, Direct Testimony of Jon A. Piliaris, Exhibit No. JAP-1CT (Dec. 15, 2016).

1 variable. Like all methods of this type, it has the advantage of relying on cost allocation
2 previously approved by the Commission for classifying costs as fixed or variable. However,
3 such cost allocation is not without controversy and may change over time, as indicated by
4 the fact that the PSE witness conducted two different calculations of stranded costs with this
5 method.³⁶ In addition, generation costs that would typically be considered fixed costs,
6 namely depreciation and financing costs of plant, are often allocated partially on the basis of
7 energy. As a result, those partially allocated costs would be considered variable costs under
8 this method. The decision to allocate such costs partially on the basis of energy is not
9 necessarily incorrect but rather something that is determined on a case-by-case basis and
10 may be influenced by prior orders.

11 **Q: Please briefly describe PSE's Proposed Approach and its pros and cons for estimating**
12 **fixed costs.**

13 A: PSE's proposed approach relied on sophisticated planning and financial modeling. Instead
14 of directly classifying costs as fixed or variable, it estimated avoided costs from the
15 customer's decision to purchase power from an alternative provider and compared it to a
16 forecast of total power-related revenue from the customer if it continued purchasing power
17 service from PSE. This method has all the pros and cons discussed in Table 1 above for
18 Planning and Financial Modeling methods. The large size of the customer's load, however,
19 made it possible for the models to detect a measurable difference in cost with and without
20 the customer. Smaller customers would not have the same impact on a similar analysis.

21 **Q: Please briefly describe PSE's Fixed PCA Costs method and its pros and cons for**
22 **estimating fixed costs.**

³⁶ Exhibit No. KAK-4, *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-161123, Piliaris, Exhibit No. JAP-1CT at 15, *see* Table.

1 A: The Fixed PCA Cost method is a direct categorization-type method. It limits fixed costs to
2 those deemed “fixed” in PSE’s PCA mechanism, including cost of capital, depreciation, and
3 production O&M, along with some additional costs such as taxes and overhead. As indicated
4 in Table 1, this method has the benefit of being easy to understand and straightforward to
5 calculate, but has issues surrounding determining the scope of fixed costs and timeframe to
6 consider. These pros and cons would be similar to those associated with Pacific Power’s
7 method in this case, which I discuss further below.

8 **VI. PACIFIC POWER’S PROPOSED STRANDED COST RECOVERY FEE**

9 **Q: Briefly summarize your understanding of why Pacific Power has a proposed Stranded**
10 **Cost Recovery Fee in addition to the right to be paid for facilities used to provide**
11 **electric service to departing customers.**

12 A: Pacific Power’s stated purpose for proposing a Stranded Cost Recovery Fee is to lessen the
13 financial impact to remaining customers after a customer decides to permanently disconnect
14 and switch to a new service provider.³⁷ In the absence of a franchise agreement, Pacific
15 Power is essentially competing with a non-regulated entity in Columbia and Walla Walla
16 Counties, and they have been impacted by duplicative infrastructure that has been and is
17 being built to serve large commercial³⁸ or high-margin Pacific Power customers.^{39, 40}

18 Pacific Power contends that the high-margin customers are being “cherry picked” by
19 the competitive supplier because they potentially offer greater revenue and profit margin

³⁷ Dalley, Exhibit No. RBD-1T at 9:14-18.

³⁸ Dalley, Exhibit No. RBD-1T at 13:13-18.

³⁹ Dalley, Exhibit No. RBD-1T at 6:4.

⁴⁰ The Company does not provide a definition for its use of the term “high-margin.” However, I assume it refers to the margin that the utility or replacement provider can earn, i.e., the difference between gross revenue received from the customer and that provider’s cost to serve the customer. Further, I assume that the term refers to the total amount of margin over time, not just the margin per unit of electric energy delivered and sold.

1 than would the acquisition of multiple smaller customers.⁴¹

2 The Stranded Cost Recovery Fee is intended to mitigate cost shifting to remaining
3 customers and recover such stranded costs associated with the departure of customers
4 seeking service elsewhere from the departing customers. Pacific Power designs their system
5 and makes resource investments to ensure reliable service based on the entire community of
6 customers. To capture the costs associated with resource investments made to serve the
7 customers leaving the system, Pacific Power proposes to charge departing customers a
8 Stranded Cost Recovery Fee before they permanently disconnect service.

9 **Q: How does Pacific Power propose to calculate a Stranded Cost Recovery Fee?**

10 A: Pacific Power proposes a different formula to calculate the Stranded Cost Recovery Fee for
11 departing residential customers versus departing non-residential customers. For residential
12 customers, the Company subtracts total residential class net power cost revenues from total
13 residential class revenues and divides the residential non-net power cost revenue by the
14 number of residential customers. The Company then uses a discount rate of 6.38 percent⁴²
15 to calculate the net present value of the non-net power cost revenue per residential customer
16 during a ten-year period.

17 The calculation for non-residential customers is the same as for residential customers
18 except that the resulting non-residential, non-net power cost revenue paid by these
19 customers during the 10-year period is divided by the average annual non-residential
20 revenue rather than by the number of customers.⁴³

21 Pacific Power proposes a single fee of \$6,153 for residential customers, arguing that

⁴¹ Dalley, Exhibit No. RBD-1T at 13:13-18.

⁴² Dalley, Exit Fee workpapers.xlsx, cells C12 and E12.

⁴³ Dalley, Exit Fee workpapers.xlsx, tab Summary Res-non Res yr1, Cell B14.

1 a single value is financially valid based on the relative invariance of service costs and load
2 size for residential customers compared to non-residential customers.⁴⁴ The Company also
3 contends that a single value provides residential customers with a clearer understanding of
4 the financial consequences of their departure.

5 For non-residential customers, Pacific Power proposes a fee based on a multiplier
6 equal to 4.5 times the annual revenue it receives from that customer class.⁴⁵ The Company
7 contends that, in contrast to the residential sector, non-residential customers do vary
8 significantly in size and load requirements.⁴⁶

9 **Q: How does Pacific Power plan to track and account for over- or under-recovery of the**
10 **Stranded Cost Recovery Fee from each customer?**

11 A: The fees collected from departing residential and non-residential customers will be tracked
12 by rate schedule and deposited in the deferral account created by the decoupling
13 mechanism.⁴⁷

14 **Q: What general methodology does Pacific Power use to calculate its Stranded Cost**
15 **Recovery Fee?**

16 A: Pacific Power uses the direct categorization method to calculate its Stranded Cost Recovery
17 Fee.

18 **Q: Please describe how Pacific Power calculates the proposed Stranded Cost Recovery**
19 **Fee.**

20 A: Pacific Power takes total projected costs for each customer class and subtracts out net power
21 costs, which it considers variable costs. All *non*-net power costs are therefore considered

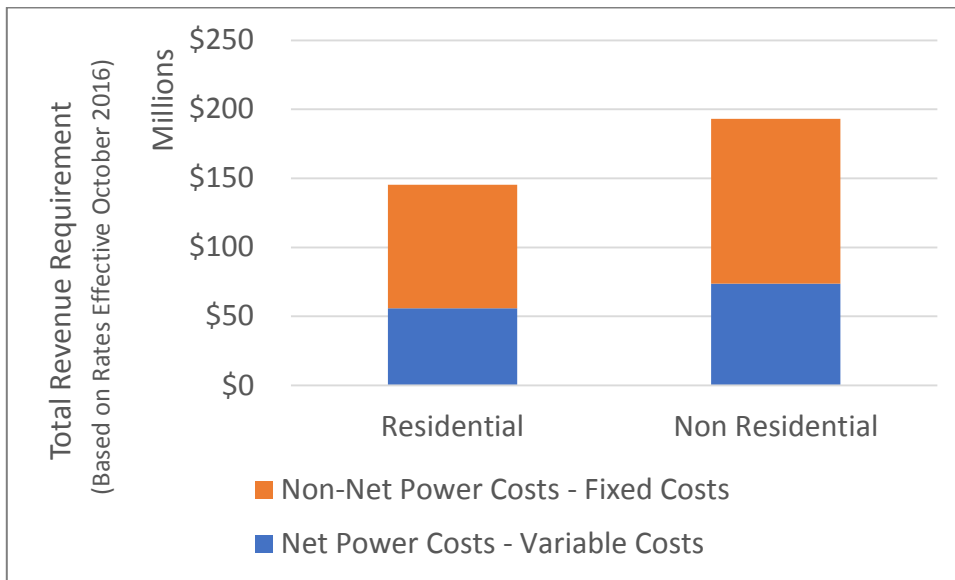
⁴⁴ Dalley, Exhibit No. RBD-1T at 15:18-22.

⁴⁵ Dalley, Exit Fee workpapers.xlsx.

⁴⁶ Dalley, Exhibit No. RBD-1T at 16:3-9.

⁴⁷ Dalley, Exhibit No. RBD-1T at 16:12-14.

1 fixed costs by Pacific Power and thereby are capable of being stranded due to a customer's
2 departure. Net power costs include fuel, wholesale power purchases, and wheeling
3 expense,⁴⁸ and are offset by wholesale sales revenue.⁴⁹ All other costs are considered fixed
4 costs, including fixed transmission costs, fixed generation costs, distribution costs (includes
5 substations, poles and conductor, line transformers and meters), customer service costs, as
6 well as administrative and general expense.⁵⁰ This definition classifies most of the costs as
7 fixed costs as shown in the chart Figure 1 below.



8
9 *Figure 1. Fixed and Variable Cost Classification by Rate Class, according to Pacific Power*
10 *recommended methodology.⁵¹*

11 **Q: How do the pros and cons of Pacific Power's proposed methodology compare to other**
12 **possible methods?**

13 **A:** The relatively small size of individual customers in Columbia and Walla Walla Counties
14 compared to the size of Pacific Power's or PacifiCorp's system make an engineering

⁴⁸ Wheeling refers to the use of another utility's transmission system to transmit power.

⁴⁹ Exhibit No. KAK-5, Pacific Power Response to Public Counsel Data Request No. 9, part b.

⁵⁰ Exhibit No. KAK-5, Pacific Power Response to Public Counsel Data Request No. 9, part e.

⁵¹ Dalley, Exhibit No. RBD-4 at 1.

1 analysis or a planning and financial modeling approach very difficult. The table below
2 compares the estimated average lost revenue per customer of departing customers to all
3 revenues collected from Pacific Power's service territory within Washington State. This
4 comparison does not consider the fact that generation and transmission costs are allocated
5 across the entire multi-state PacifiCorp system. Attempting to detect the impact of the
6 departure of one Walla Walla customer to the entire PacifiCorp system using a sophisticated
7 model such as the one PSE used in its Proposed Approach would not make sense. The
8 difference would be within the tolerance band of a production cost model's optimization
9 algorithm.⁵²

10 **Table 2: Lost revenue per customer of departed customers compared to**
11 **Pacific Power's total Washington State revenues.**

| | |
|--|----------------------|
| Total 2016 Lost Revenue ⁵³ | \$1,872,305 |
| Number of Lost Customers ⁵⁴ | <u>68</u> |
| Revenue per Customer | \$27,534 |
| Total 2016 Revenue, Incl. Lost Revenue ⁵⁵ | <u>\$340,425,366</u> |
| %Revenue Lost per Lost Customer | 0.008% |

12 Direct categorization avoids the problems with using a cost allocation method since fixed
13 costs, such as the cost of generation plant, can be allocated different ways and may be
14 controversial. Direct categorization is also easier to understand.

15 However, using direct categorization comes with potential pitfalls described below:

- 16
- **Scope:** One must still classify all costs as fixed or variable in some fashion, which

⁵² Production costing models, such as AURORAxmp used by PSE, simulate the dispatch of the power grid and attempt to optimize the dispatch to minimize production costs. The sophisticated optimization algorithms the models use are never perfectly optimized, however. They are optimized only to within a certain band of uncertainty, or tolerance band. Thus, small perturbations in the modeling inputs would be unlikely to change the optimization outcome in a logical way.

⁵³ Dalley, Exhibit No. RBD-3.

⁵⁴ Dalley, Pacific Power PDR Workpapers in support of Exhibit No RBD-3.

⁵⁵ Dalley, Exhibit No. RBD-4. Excludes lighting customers.

1 may be controversial.

2 • **Timeframe:** No cost is fixed over a long enough time horizon. Plant is retired and
3 replaced, and planners can adjust to the new system configuration without the
4 departed customers. Useful life of the specific facility components, if considered,
5 may change the value of the infrastructure installed to serve each departing customer,
6 and thus the magnitude of the stranded cost fee. If the infrastructure is near the end
7 of its useful life, then theoretically the stranded cost fee should be lower than for a
8 customer whose service infrastructure has a high concentration of new facility
9 components.

10 • **Customer Differences:** Individual customers have different total consumption and
11 load patterns⁵⁶ and, therefore, cause different fixed costs to be incurred by the utility.
12 Looking only at total utility fixed costs would not capture this variation.

13 **Q: Is the Company's selection of a direct categorization approach reasonable in light of**
14 **the pros and cons of each approach?**

15 A: Yes, but the issues of scope, timeframe, and customer differences discussed above are
16 important and should be carefully considered. I turn to these issues next.

17 **Q: Are scope and timeframe issues related?**

18 A: Yes. In the short-term, over just one-to-two years, many utility costs are essentially fixed.
19 Utilities cannot easily sell off and replace existing infrastructure or alter its labor force in
20 response to loss of load due to departing customers within that timeframe. However, over a
21 long-enough term, sometimes decades for certain long-lived utility assets, plant is retired
22 and replaced, and all investments and operating costs will have adapted to the loss of the

⁵⁶ Load pattern refers to how a customer's demand changes over time, especially when its demand peaks compared to other customers. Utility costs tend to be higher during times of peak system demands.

1 customer. At that point, there will be no more stranded costs.

2 **Q: What scope of cost types and timeframe has the Company recommended in its**
3 **approach to determining fixed costs?**

4 A: Pacific Power has assumed all non-net power costs to be fixed⁵⁷ over a ten-year period,
5 which is twice the length of the five-year period PSE assumed in its proposed approach. I
6 agree that net power costs are variable in nature and can be avoided with lower load, so it is
7 appropriate to exclude those costs from fixed costs. The only questions are whether the
8 scope of fixed costs is appropriate and if the analytical timeframe should be adjusted.

9 **Q: What costs may not be “fixed” given the ten-year timeframe of the Company’s**
10 **analysis?**

11 A: There are several costs that Pacific Power has included in its scope of fixed costs that are
12 unlikely to be fixed for 10 years. Here are some examples:

- 13 • With fewer customers, the utility will issue fewer bills, which can lower meter
14 reading and billing costs, even in the short-term.
- 15 • Customer service and other labor costs can be adjusted over that time as the utility
16 makes hiring decisions.
- 17 • Meters can be reused for other customers and defer new metering investment.
- 18 • Certain plant will be retired and replaced in that time, although some will also outlast
19 it.

20 **Q: Did the Company consider alternative timeframes for the analysis?**

21 A: Yes. Pacific Power also considered calculating the net present value of fixed costs over 20,

⁵⁷ Exhibit No. KAK-6, Pacific Power Response to CREA Data Request No. 39, part d; Exhibit No. KAK-5, Pacific Power Response to Public Counsel Data Request No. 9, part c.

1 15, 8, 6, and 4 years.⁵⁸ It ultimately selected a 10-year timeframe as reasonable “in light of
2 the Company's long-term planning cycle.”⁵⁹

3 **Q: How would changing the timeframe impact the Stranded Cost Recovery Fee?**

4 A: The table below compares the Stranded Cost Recovery Fee for different assumed
5 timeframes. The amount varies substantially, depending on what timeframe is assumed.

6 **Table 3: Impact of timeframe on proposed Stranded Cost Recovery Fee.**⁶⁰

| Timeframe | Residential Fee | Non-Residential Revenue Multiplier |
|-----------|-----------------|------------------------------------|
| 4 years | \$2,924 | 2.1 |
| 6 years | \$4,136 | 3.0 |
| 8 years | \$5,206 | 3.8 |
| 10 years | \$6,153 | 4.5 |
| 15 years | \$8,065 | 5.9 |
| 20 years | \$9,468 | 6.9 |

7 **Q: Please provide an example illustrating how altering the scope of fixed costs impact**
8 **could lower the Stranded Cost Recovery Fee.**

9 A: Figure 2 below also provides a functionalized breakdown by rate class of all non-net power
10 costs based on Pacific Power’s most recent Cost of Service study.⁶¹

11 If some portion of these costs were removed from consideration as fixed costs, the
12 Stranded Cost Recovery Fee would decrease accordingly. Assume, for example, that the
13 Retail function was excluded from the Stranded Cost Recovery Fee for residential
14 customers. Since the Retail function represents about five percent of revenue requirement,
15 the Stranded Cost Recovery Fee would be reduced about five percent. This is approximate,
16 however, since a) rates are not set exactly at total Cost of Service as output from the Cost of

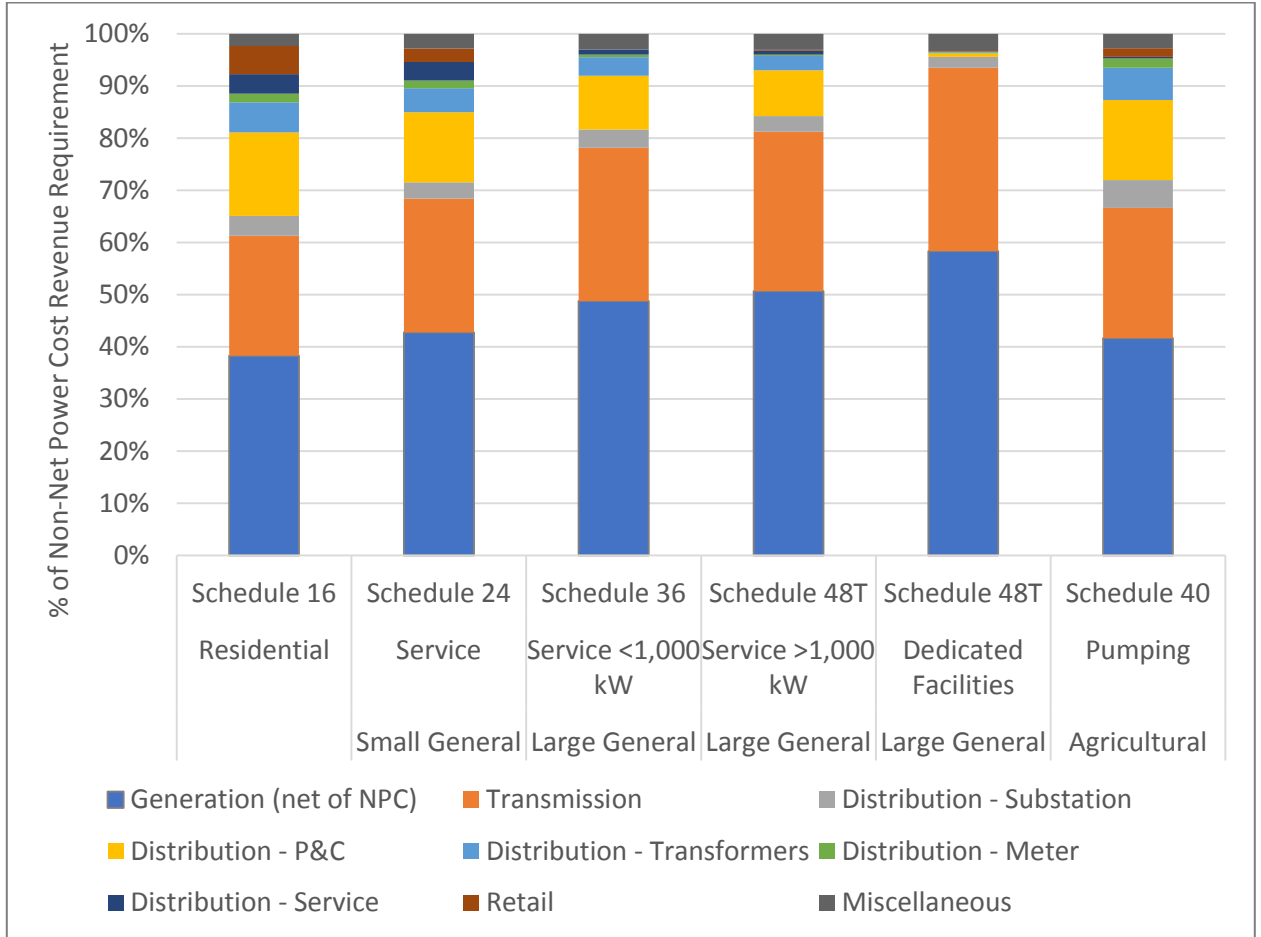
⁵⁸ Exhibit No. KAK-7, Pacific Power Response to Boise Data Request No. 34, part c.

⁵⁹ Exhibit No. KAK-8, Pacific Power Response to Boise Data Request No. 56.

⁶⁰ Exhibit No. KAK-7, Pacific Power Response to Boise Data Request No. 34, Electronic Attachment.

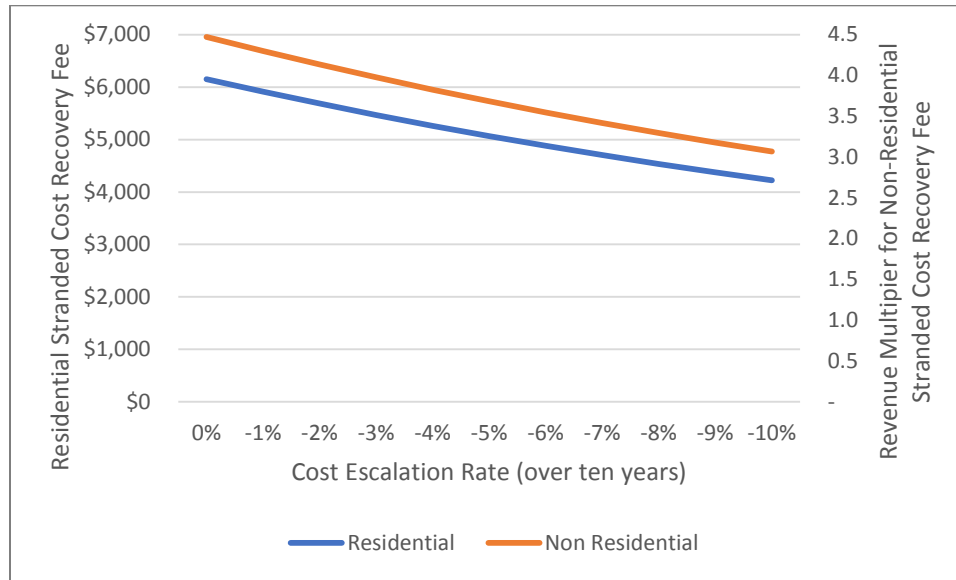
⁶¹ Exhibit No. KAK-9.

1 Service study, and b) the Cost of Service study is based on calendar year 2013 while the
 2 Stranded Cost Recovery Fee is based on revenues from rates effective October 2016.



3
 4 *Figure 2. Functional Breakdown of Non-Net Power Cost Revenue Requirement by*
 5 *Customer Class. Based on COS study provided in Attachment 1 to Pacific Power Response*
 6 *to Boise Data Request No. 52.*

7 Another way to reduce the amount of fixed costs is to adjust the growth assumption. The
 8 Company could consider including a declining growth rate, rather than zero percent or no
 9 growth) to reduce the annual fixed cost estimate over time as a way to account for plant
 10 retirements. The chart below shows how the Stranded Cost Recovery Fee changes in
 11 response to various cost de-escalation rates over 10 years.



1

2 *Figure 3. Change in Stranded Cost Recovery Fee for Residential and Non-Residential*
3 *Customers Assuming Costs De-escalate over Ten Years.*

4 **Q: How has the Company accounted for customer differences in determining the**
5 **Stranded Cost Recovery Fee?**

6 A: The Company uses a different approach for residential and non-residential customers. For
7 residential customers, it calculates a flat per-customer fee that is the same for all customers.
8 For non-residential customers, it uses a revenue multiplier. Each non-residential customer
9 would pay a lump sum equal to the multiplier times their annual revenue.

10 **Q: What issues do you find with the Company’s approach to calculating a flat fee for**
11 **residential customers?**

12 A: The use of a flat fee for residential customers puts smaller residential customers at a
13 disadvantage compared to a revenue multiplier approach. The Company justifies its
14 calculation by stating that the “costs incurred to serve residential customers as well as the
15 size of their loads typically do not vary to the same extent as for non-residential customers”
16 and that “[u]sing a single value for residential customers will help them to more easily

1 understand the financial impact of leaving the Company’s system.”⁶² While a single, fixed
2 dollar amount may be easier to understand in one sense, it is based on an unsupported
3 assumption that costs do not vary widely with respect to residential customer load, nor does
4 it provide an appeal mechanism for an individual residential customer to seek a reduction
5 based on evidence.

6 **Q: What issues do you find with the Company’s approach using a multiplier to calculate a**
7 **Stranded Cost Recovery Fee for non-residential customers?**

8 A: Although Pacific Power does not differentiate among the non-residential customers, the
9 differences between those customer classes is relatively small, as demonstrated in Table 4
10 below. Table 4 shows that the multiplier is slightly advantageous for Schedule 40 and
11 Schedule 24 customers, is neutral for Schedule 36 customers, and is slightly
12 disadvantageous for Schedule 48 customers, suggesting that, on balance, use of the proposed
13 multiplier is fair.

14 **Table 4: Revenue multiplier (“Investment to Revenue Ratio”) for stranded cost**
15 **recovery for each non-residential rate class per Pacific Power’s proposed**
16 **methodology.**⁶³

| | Sch 24 | Sch 36 | Sch 40 | Sch 48 | All Non-Residential |
|--------------------|--------|--------|--------|--------|---------------------|
| Revenue Multiplier | 4.7 | 4.5 | 4.9 | 4.2 | 4.5 |

17
18 **A. Determining Additional Market Revenues.**

19 **Q: How does a customer leaving the system create opportunities for the original provider**
20 **to reduce net power costs?**

21 A: Pacific Power not only generates power to serve its own load, it also buys and sells power

⁶² Dalley, Exhibit No. RBD-1T at 15:19-22.
⁶³ Dalley, Exhibit No. RBD-4, electronic spreadsheet tab “Exhibit No. RBD-4, pages 2-4.”

1 into the regional power market.⁶⁴ The ability to reduce net power costs related to purchases
2 and sales in the power market is a function of both volume and market price. To answer this
3 question, we look at each variable in isolation while holding the other factors constant. The
4 slice of generation previously used to serve a customer that has permanently disconnected
5 from the system, after determining it is not needed for growth in existing load, becomes
6 excess to on-system requirements. The effect that excess generation has on the utility's
7 ability to generate revenue depends on when it becomes available.

8 If the departing customer consumes power during times the utility is purchasing
9 power, that customer's departure lowers the volume to be purchased in the market. In other
10 words, at some point during the day, the utility already planned to supplement on-system
11 generation with market purchases. As a result, the effect of the departing customer is only
12 to reduce the amount the utility needed to buy above generation capacity, thereby reducing
13 net power costs for the remaining customers. This scenario assumes the prevailing market
14 price for volumes purchased does not increase in the short-run to offset the volume induced
15 savings.

16 Alternatively, if the departing customer consumes power during times when the
17 Company is selling (rather than buying) power, the customer's departure may increase
18 revenue from market sales by increasing the volume available for sale.

19 **Q: How does the Company estimate additional market revenues for purposes of**
20 **calculating the Stranded Cost Recovery Fee?**

21 **A:** The Company does not explicitly consider any ability to collect additional margin from
22 market sales as part of its analysis of stranded costs.

⁶⁴ This may include bilateral markets and California ISO markets, including the new energy imbalance market.

1 **Q: Once the availability of excess generation for market sales is determined, how would**
2 **the utility capture additional market revenue to offset fixed cost recovery?**

3 A: Once a utility determines that it has generation in excess of its needs, the decision to sell is
4 based on the prevailing market price compared to the utility's incremental cost of
5 generation. Some generating units have higher variable costs than others, with all the units
6 in operation at the same time contributing to incremental cost.

7 When incremental cost is less than market price, the utility may decide to sell excess
8 generation to generate revenue (where revenue is equal to the energy market price multiplied
9 by the volume sold). Some of this market revenue pays for the incremental cost to generate,
10 and the remaining revenue is essentially profit on the deal that can be used to offset fixed
11 costs.

12 If incremental costs are equal to the market price, the utility may generate to sell into
13 the market, but incremental revenue would exactly offset incremental cost, leaving net
14 power costs unchanged.

15 **Q: Are there circumstances where a customer leaving the system does *not* create**
16 **opportunities for the original provider to make market sales but still be able to offset**
17 **fixed costs?**

18 A: Yes, when incremental cost is greater than the market price, then the utility would elect not
19 to generate to make a sale, but instead to reduce generation by the amount of the departing
20 customer's load. This would reduce total generation and net power costs would decrease.

21 **Q: Is it possible to estimate such margin and resulting increases in market revenue that**
22 **would contribute toward fixed cost recovery?**

23 A: Yes, this can be accomplished using sophisticated models that simulate and optimize utility

1 or regional generation dispatch. PSE presented this type of analysis in its proposed
2 approach in Docket UE-161123, the aforementioned docket in which PSE proposed a new
3 tariff to allow large customers to seek generation service from alternative suppliers. Use of
4 a dispatch model to dispatch its system against a market price and a load curve with and
5 without the customer's load is an accepted practice because it would capture changes in
6 market purchases and sales revenues, including any increased margin on market sales.⁶⁵

7 **Q: What limitations are there to market modeling that makes it difficult to quantify**
8 **changes in the Company's market revenues and margins due to departing customers**
9 **in Walla Walla and Columbia counties?**

10 A. There are three primary limitations. First, the calculation and dispatch depends on market
11 prices, which are uncertain. Weather patterns can significantly impact market prices.
12 Drought or unseasonably wet weather will decrease or increase hydro power availability,
13 which can increase or decrease market prices. Weather can also impact fuel prices, as very
14 warm summer weather can cause periods of exceptional electric demand, which can increase
15 prices. Very cold winter weather can increase natural gas fuel demand and hence natural gas
16 prices, which influence market prices. Uncertainty in regulatory policy around emissions
17 limits and renewable portfolio standards, as well as uncertainty in technological

⁶⁵ See, e.g. Fla. Pub. Serv. Comm'n, REPLACEMENT COST METHOD OF VALUING UTILITY GENERATION ASSETS 6 (2001), which concludes that use of a dispatch model can provide an estimate of stranded asset value.

As mentioned earlier, it is the discounted revenue and profit produced by an asset that is the final arbitrator of value. This static analysis should be extended by performing a multi-year economic dispatch model for Florida under various natural gas price scenarios. The difference between cost-based production and market clearing prices could be estimated given the current load and energy projections. By present valuing the difference between production and clearing prices and adjusting for the required after tax return on capital, one could begin to assign a specific market value to these units. In addition to estimating the stranded value, this type of dynamic study would provide more reliable estimates of both production costs and the likely shift in costs to customers.

1 development also make forecasting market prices more difficult. In addition, it is very
2 difficult to determine after the fact whether changes in total revenues, including changes in
3 margin, were due to a departing customer or due to changes in the market environment more
4 generally.

5 Second, Pacific Power's customers are relatively smaller compared to the large
6 commercial customer in the PSE case, Docket UE-161123, in which it modeled the loss of
7 load from one large industrial customer. In fact, the model would have difficulty detecting
8 any difference with and without a typical Walla Walla customer included in total load to be
9 served. Although these models use sophisticated optimization algorithms, they are
10 optimized using a tolerance band that could result in such small changes in inputs creating
11 conditions that translate into increased costs due to departing customers.

12 Third, running such models for each departing customer would be time consuming
13 and costly for a utility to perform, and not easily understood by departing customers.

14 **Q: Are there acceptable alternative methods available to estimate changes in market**
15 **revenues without relying on sophisticated production cost models?**

16 A: Not in my opinion. I am not aware of any methodologically rigorous way to estimate
17 market revenue changes without using a production costing model. Although it may be
18 possible to take a simplified approach or analyze the "generic" customer, such approaches
19 do not eliminate the issues with uncertainty in the forecast. Without a way to true up
20 estimates of additional margin to actual margin based on actual market conditions, the
21 utility would end up in a situation where some customers may be penalized by or benefit
22 from forecasting error. As its forecast changes over time, different customers may pay
23 different Stranded Cost Recovery Fees and may not understand why they pay something

1 higher or lower than a neighboring customer.

2 **B. Issues Related to Stranded Cost Recovery Fee Sensitivity Analysis.**

3 **Q: Please explain how you define “additional issues” related to the Stranded Cost**
4 **Recovery Fee?**

5 A: Sections A and B above discussed fundamental methodological issues surrounding
6 estimating fixed costs. Below, I discuss the impact (i.e., sensitivity) of the calculation of
7 the Stranded Cost Recovery Fee due to changes in assumed values for specific driver
8 variables used in Pacific Power’s methodology, including:

- 9 • Impact of loss of load from a departing customer on cost allocators in the Cost of
10 Service Study;
- 11 • Other impacts of changes in load and number of customers over time; and
- 12 • Potential for avoided cost benefits from deferred investment.

13 **Q: Please describe how loss of load impacting cost allocators used to calculate the**
14 **Stranded Cost Recovery Fee.**

15 A: Pacific Power operates a multi-state system and allocates costs to each jurisdiction in its
16 Jurisdictional Allocation Model (JAM), which is part of its Cost of Service model. The
17 JAM allocation factors depend on the loads in each jurisdiction. As the Company explains:

18 If a customer disconnects from Pacific Power's system in Washington,
19 assuming no other changes, Washington's allocation factors would decrease.
20 The reduced allocation factor would impact Washington's allocation of costs
21 that are shared between jurisdictions. It would not, however, reduce
22 Washington's share of situs investments since those amounts are not allocated
23 between states. Any shift of costs associated with situs investments would be
24 borne by remaining Washington customers.⁶⁶

25 The Company also uses allocation factors to allocate the Washington state jurisdictional

⁶⁶ Exhibit No. KAK-10, Pacific Power Response to Boise Data Request No. 54.

1 revenue requirement, as determined by the JAM, to different rate classes in the state.

2 **Q: What do you conclude about the proposed Stranded Cost Recovery Fee based on your**
3 **finding regarding loss of load impacting cost allocators?**

4 A: I have two concerns based on my review of the evidence filed in this docket.

5 First, Pacific Power did not account for the change in any allocation factors due to
6 load from departing customers when calculating the Stranded Cost Recovery Fee.⁶⁷

7 However, doing so would require redoing a Cost of Service study, which is a labor and
8 time-intensive study. Moreover, the Cost of Service study would impact how stranded costs
9 are borne by different jurisdictions and rate classes after a customer's departure, but it would
10 not change the essential fact that fixed costs remain fixed and must be paid for by remaining
11 customers after another leaves the system without some kind of fee to recover stranded costs
12 from departing customers.

13 Second, Pacific Power's proposed Stranded Cost Recovery Fee includes the cost of
14 facilities that the departing customer would have already paid for whether it chose to
15 purchase facilities necessary to supply electricity and transfer them to the replacement
16 provider or paid the Actual Cost of Removal of All Facilities not sold, as specified in the
17 proposed revision to Rule 6. I address this specific concern in more detail in Section D,
18 Policy Issues Raised by the Proposed Stranded Cost Recovery Fee, below.

19 **Q: Please explain how changes in number of customers over time impact the Stranded**
20 **Cost Recovery Fee.**

21 A: The number of customers is a key driver variable because it is used in the denominator of a
22 ratio that represents the undiscounted Stranded Cost Recovery Fee. As a result, non-trivial

⁶⁷ Exhibit No. KAK-11, Pacific Power Response to Boise Data Request No. 55.

1 changes in customer count can have a noticeable impact on the Stranded Cost Recovery Fee.

2 Pacific Power estimates the Stranded Cost Recovery Fee for each rate class schedule
3 by calculating average total revenue per customer and average non-net power costs per
4 customer. The Company then takes the 10-year net present value of the average non-net
5 power costs per customer and divides it by the average total revenue per customer to get the
6 multiplier used to set the rate for Non-Residential customers.

7 The Company proposes using the net present value of the non-net power costs over
8 10 years as the flat fee for Residential customers.⁶⁸ Since the multiplier is based on average
9 revenue per customer, a small increase in number of customers, e.g., five percent (5%)
10 produces an equal magnitude reduction in the net present value, the estimate of stranded cost
11 apportioned to the departing customer.

12 The net present value of this estimate of stranded cost per customer is used to
13 calculate the flat rate for Residential customers. The multiplier used for Non-Residential
14 customers remains the same because the change in customers impacts both the numerator
15 and the denominator.

16 **Q: What does the Company assume for customer growth in its proposed Stranded Cost**
17 **Recovery Fee?**

18 **A:** Pacific Power assumes that the number of customers derives from the same 12-month period
19 ending June 2015 used to estimate fixed costs.⁶⁹ The Company also does not assume any
20 load growth over the 10-year period of its analysis.⁷⁰ The Company argues that its

⁶⁸ Even though non-net power costs are a subset of total revenue, when summed over 10 years and used in the numerator, the result is a multiplier greater than one.

⁶⁹ Exhibit No. KAK-6, Pacific Power Response to CREA Data Request No. 39, part a.

⁷⁰ Exhibit No. KAK-6, Pacific Power Response to CREA Data Request No. 39, part b.

1 Washington loads have been flat to declining over the past several years,⁷¹ which the
2 Company claims indicate that such an adjustment would be unnecessary.

3 **Q: Do you agree with the Company’s customer growth assumption?**

4 A: I agree that many utilities are facing slow load growth even with a significant increase in
5 customer count. I would point out that despite some justification for holding the customer
6 count constant over time, there are reasons to anticipate some growth in the future in either
7 customer count or total revenue per customer. Furthermore, the zero-growth assumption
8 ignores technology driven changes in demand per customer such as recharging service for
9 electric vehicles and distributed generation, tariffs offerings for which are under
10 consideration by several utilities across the country at this time. As a result, the Company
11 should determine the potential for customer growth for these and similar reasons and reflect
12 the impact of that growth in its analysis of the Stranded Cost Recovery Fee.

13 **Q: How is the potential for avoided cost benefits due to deferred investments reflected in**
14 **the proposed Stranded Cost Recovery Fee?**

15 A: One way to reflect the potential for avoided cost benefits due to deferred investments
16 is to consider future infrastructure investment needs, which will be reflected in the utility’s
17 integrated resource planning. Pacific Power acknowledges that it “has not evaluated the
18 impact of permanent disconnections on future infrastructure costs,” and argues that “net
19 benefits to remaining customers can only be achieved if the impact is large enough to defer
20 or eliminate the need for future investments.”⁷² Contrast this approach with the approach
21 taken by PSE in Docket UE-161123. PSE estimated a future benefit to remaining customers
22 due to a large customer electing to take service from another supplier and to a deferred need

⁷¹ Exhibit No. KAK-6, Pacific Power Response to CREA Data Request No. 39, part b.

⁷² Exhibit No. KAK-12, Pacific Power Response to Boise Data Request No. 1, part a.

1 for new generation investment after Colstrip Units 1 and 2 retire in 2022.⁷³

2 The preferred portfolio from PacifiCorp's most recent 2015 Integrated Resource Plan
3 ("2015 IRP") does not show a need for new generating capacity until 2028,⁷⁴ which is just
4 beyond the 10-year period of used in its spreadsheet model analysis. Therefore, based on
5 the 2015 IRP, it would be unlikely for a customer departing Pacific Power's system to cause
6 remaining customers to receive a benefit from deferred investment until very far into the
7 future.

8 In evaluating what time horizon is appropriate to use to calculate stranded costs
9 when a utility's customer leaves its system to take service from another provider, the time
10 horizon should allow the utility to review the potential changes to its resource portfolio and
11 demand requirements over two or three IRP planning cycles. This recognizes that changes
12 in the portfolio or the market price for power may occur in later years.

13 **Q: What do you conclude with respect to the time horizon that is appropriate to calculate**
14 **Pacific Power's Stranded Cost Recovery Fee?**

15 A: I conclude that it would be more appropriate to use a shorter time period to calculate Pacific
16 Power's Stranded Cost Recovery Fee. Pacific Power's proposal assumes a static situation
17 for a full 10 years. I recommend that the Stranded Cost Recovery Fee for each customer be
18 based on six-year time horizon, which is approximately equal to three IRP planning cycles.
19 As a result, the Company would have the opportunity to revise its market outlook, demand
20 forecast, and resource portfolio at least twice. We discussed the Company's 2015 IRP
21 above and note that it has recently filed its 2017 IRP, illustrating a two-year interval

⁷³ Exhibit No. KAK-4, *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-161123, Exhibit No. JAP-1CT at 6:6-13.

⁷⁴ Exhibit No. KAK-12, Pacific Power Response to Boise Data Request No. 1, part b.

1 between proceedings.⁷⁵ Thus, a six-year time frame provides the opportunity to reflect near
2 term changes in the marketplace as reflected in an updated and approved IRP.

3 **C. Policy Issues Raised by the Proposed Stranded Cost Recovery Fee.**

4 **Q: Please summarize the policy issues your analysis finds have been raised by Pacific**
5 **Power's proposed Stranded Cost Recovery Fee.**

6 A: I find that Pacific Power's proposed Stranded Cost Recovery Fee raises four policy issues
7 listed below:

- 8 • The proposed rates and fees are not consistent with the principle of cost causation.
- 9 • The Company's presumption to have sole discretion to determine which facilities are
10 to be included in the Stranded Cost Recovery Fee calculation raises the risk of
11 double collection for the same cost.
- 12 • The Company's presumption that it has sole discretion to determine which facilities
13 when abandoned in place create a safety risk (discussed in Section E below) without
14 deference to standing procedures for determining the presences of such a risk with
15 neighboring utilities and local first responder authorities.

16 **Q: Please summarize the issue with cost causation and the Stranded Cost Recovery Fee.**

17 A: Pacific Power's proposed Stranded Cost Recovery Fee is not consistent with the principles
18 of cost causation and just and reasonable rates. The Company says that its proposed
19 Stranded Cost Recovery Fee is based on non-net power costs by customer class. As shown
20 in Figure 1 above, non-net power generation costs (orange bars) are equal to 61.6 percent of

⁷⁵ Pacific Power, 2017 INTEGRATED RESOURCE PLAN VOLUME I (Apr. 4, 2016),
https://www.pacificpower.net/content/dam/pacificcorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf.

1 residential revenue requirement and 61.9 percent of non-residential revenue requirements. If
2 approved, this means that departing customers essentially must continue to pay most of their
3 current retail rate for the next 10 years in one upfront, discounted lump sum. Pacific Power
4 will receive this payment even after it is no longer responsible to plan for and provide
5 service to departing customers because those customers will have transferred all electric
6 load and facilities to another provider for the next decade. Under Pacific Power's proposal,
7 it would receive the Stranded Cost Recovery Fee even in situations where conditions later
8 change to increase load or alter generation mix in a way that reduces stranded fixed costs.
9 As a result, the Stranded Cost Recovery Fee as proposed is inappropriately designed.

10 **Q: Is Pacific Power correct to expect to be able to recover stranded costs created by the**
11 **departing customers request to permanently disconnect from the system?**

12 A: Yes, based on my review of the conditions that give rise to stranded costs, Pacific Power's
13 request is consistent with conditions that are beyond its control to some extent. The
14 controlling factor that creates the situation in this case is the absence of a prevailing
15 franchise agreement that would grant Pacific Power exclusive rights to serve customers
16 within a defined service territory. Pacific Power argues, correctly, that due to the regulatory
17 construct under which it installed infrastructure to serve such customers, these customers
18 should not be able to shift responsibility to pay their share of the fixed costs of the system
19 investments made to serve them to other customers. The issue here is not whether Pacific
20 Power should be allowed to recover stranded costs from departing customers, but rather
21 what time period is appropriate to use to measure the stranded costs.

22 **Q: Besides the 10-year time horizon, do you have other criticisms of the proposed**
23 **methodology to recover stranded costs?**

1 A: Yes. Pacific Power's definition of what constitutes a stranded cost in the proposed tariff
2 revision is defined both too broadly and too narrowly.

3 **Q: Why do you believe that the Company's definition of stranded cost is too broad?**

4 A: Under Pacific Power's proposed methodology, the Company possesses sole discretion to
5 define the facilities to be recovered in the Stranded Cost Recovery Fee. As a result,
6 customers risk that the Company will over-designate the facilities to be recovered in the
7 Stranded Cost Recovery Fee. The result would be that customers would pay for more
8 facilities than are included in the minimum necessary for (1) sale and transfer, (2) transfer,
9 or (3) removal or abandonment upon permanent disconnection.

10 Pacific Power's broad categorization of facilities, plus lack of accounting in the
11 stranded cost model for any increases in market revenues, load growth, or allocation
12 changes, ignores important complexities of utility planning and principles of ratemaking.
13 For example, one risk is that the Company could recover costs for the same expense twice.
14 In response to discovery, the Company acknowledged that certain facilities costs would be
15 included in its Stranded Cost Recovery Fee calculation that may be paid for in the Actual
16 Cost of Removal or that would decline upon the customer's departure.⁷⁶ Examples include
17 meters and related distribution facilities costs and customer service costs.

18 **Q: Why do believe the Company's stranded cost definition is too narrow?**

19 Pacific Power's proposed definition of stranded cost is defined too narrowly because it
20 excludes consideration for the departing customer's obligation to support the Company's
21 commitment to low-income rate assistance and energy efficiency programs. Without
22 recognition of these costs in the stranded cost calculation, the costs will either shift to the

⁷⁶ Exhibit No. KAK-5, Pacific Power Response to Public Counsel Data Request No. 9, part e.

1 remaining customers or the overall contribution made to these programs will decrease.

2 **Q: Does the Company recognize that their proposed definition of stranded cost does not**
3 **take low-income rate assistance and energy efficiency into account?**

4 A: Yes. The Company stated in response to discovery that it did not specifically consider the
5 consequences that a departing customer's decision to leave the Company's system would
6 have on these programs and agrees that its proposed Stranded Cost Recovery Fee should be
7 revised accordingly, but offers no specific change at this time.⁷⁷

8 **Q: Please describe modifications you would make to the Company's methodology for**
9 **calculating its proposed Stranded Cost Recovery Fee.**

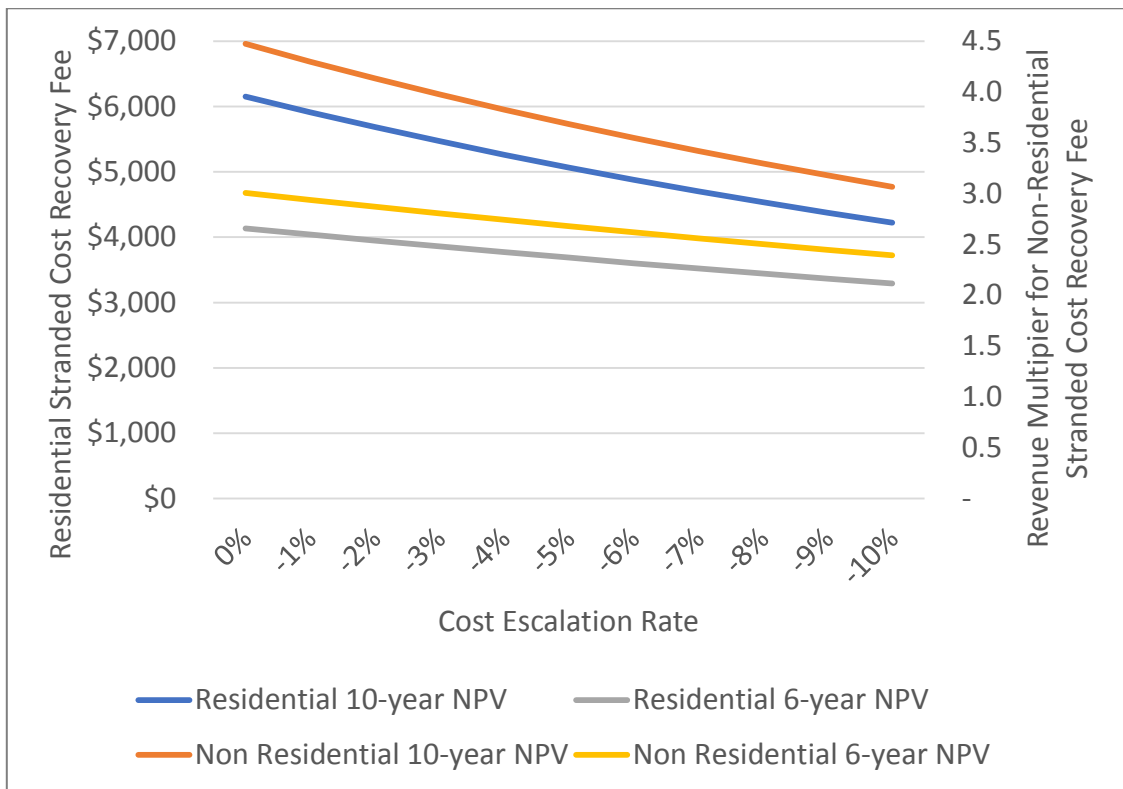
10 A: It is important to recognize that there is a trade-off between the accuracy gained from
11 estimating these adjustments in an analytically rigorous way, while providing the customer
12 with an easy-to-understand fee structure. In my experience, including my experience as a
13 utility executive, most residential customers can evaluate their service options based on a
14 multiplier as easily as they can when given a flat-fee option. Thus, the flat fee should only
15 be provided as a cap for the residential customer rate, below which a multiplier would be
16 used. Non-Residential customers' fees should be determined by a multiplier as originally
17 proposed because these customers are likely to depart upon being offered incentives from a
18 competitive supplier.

19 My review of the Company's stranded cost calculation model shows that it is very
20 sensitive to the time horizon used to calculate the net present value of stranded cost.

21 Assuming a six-year time horizon produces the additional two fixed-fee cost curves shown
22 in Figure 4 below, which lie far below the 10-year cost curves when assuming little or no

⁷⁷ Exhibit No. KAK-13, Pacific Power Response to Public Counsel Data Request No. 16, part b.

1 reduction in fixed costs. Interestingly, the two sets of cost curves move closer together as
 2 greater reductions in fixed cost are assumed. I do not recommend a specific assumption for
 3 a negative growth rate for fixed costs at this time because this assumption should be
 4 established following the results of an updated Cost of Service Study confirming the full
 5 scope of fixed cost. Instead, I focus on how the scope of fixed costs could change.



6
 7 *Figure 4. Fixed-Fee Cost Curve for Six Years versus Ten-Years: Change in Stranded Cost*
 8 *Recovery Fee for Residential and Non-Residential customers assuming costs de-escalate*
 9 *calculated over a six-year horizon compared to a ten-year horizon.*

10 The value at the far left side of the Figure 4 shows that under the Company's
 11 assumption of no change in fixed costs over time the flat fee for the Residential class would
 12 be \$4,136, or \$2,017 and 32 percent less than the Company's proposed rate of \$6,153.
 13 However, it is imperative to emphasize that including only valid costs in the first place could
 14 have as big an impact on any proposed flat fee as employing a shorter time horizon. This is

1 also consistent with the principle of cost causation and the prohibition on collecting for the
2 same cost more than once in rates.

3 **Q: What do you conclude based on the observed sensitivity of the flat fee to variations in**
4 **the time horizon and the risk of collecting for the same cost more than once?**

5 A: I conclude that Pacific Power's proposed Stranded Cost Recovery Fee for Residential
6 customers is too high. I also believe that an updated Cost of Service study would be useful
7 in determining the stranded costs for each rate class. However, because Pacific Power does
8 not have an updated Cost of Service study, the Company's stranded cost calculation model
9 should be modified to better calculate a fair Stranded Cost Recovery Fee. The Company's
10 model is flawed in its sensitivity to the time horizon. However, it can be modified by
11 shortening the time horizon to reflect a more realistic period in which the utility will
12 experience stranded costs. The Company has proposed a ten-year horizon; however, I
13 believe it should be a six-year horizon, which corresponds to a multiple of 3.0, as shown in
14 Table 3 above. This and my additional recommended changes to the Company's
15 methodology are summarized below:

- 16 1) Shorten the time period for the analysis from ten to no more than six years.
- 17 2) Use a multiplier times annual cost of service to determine the Stranded Cost
18 Recovery Fee for each customer, including a multiplier of 3.0 for Residential
19 customers and a multiplier of 4.5 for Non-Residential customer classes.
- 20 3) Set a cap on the Stranded Cost Recovery Fee for Residential Customers equal to
21 \$4,138, the amount calculated using the Company's model and based on a six-year
22 time horizon (a one-third reduction in the Company's proposed fee).
- 23 4) Relinquish the Company's presumption of having sole discretion in favor of

1 requiring an independent review and appraisal of facilities being sold, transferred or
2 abandoned with each Disconnection and Removal request, unless a waiver has been
3 requested and granted by the Commission.

4 **Q: Please explain your understanding of why there is no franchise agreement in place**
5 **between Pacific Power and the counties in which it operates.**

6 A: The Company states that electric utilities have been operating under negotiated service area
7 agreements with other utilities, including public utility districts, municipal utility districts,
8 rural electric associations, and cooperatives because Washington State does not require
9 designation of exclusive service areas by statute.⁷⁸ The Company had a formal service area
10 agreement in place with Benton Rural Electric Association for 20 years, which recently was
11 renewed for another 20-year term.⁷⁹ However, they had only an informal understanding
12 with Columbia Rural Electric Association (CREA) to install facilities to serve customers in
13 Columbia County and Walla Walla County based on how close each customer's premise
14 was to the Company's or CREA's distribution facilities.⁸⁰ The Company has been unable to
15 secure through negotiation a more formal service agreement,⁸¹ and in that void, has
16 "sustained gradual revenue loss"⁸² due to several large customers requesting disconnection
17 from Pacific Power in favor of being served by CREA, who has offered rates that are
18 locked-in for five years, among other incentives.⁸³

19 **Q: What has been the consequence of Pacific Power losing customers to CREA?**

⁷⁸ Dalley, Exhibit No. RBD-1T at 2:19-20.

⁷⁹ Dalley, Exhibit No. RBD-1T at 4:6-9.

⁸⁰ Dalley, Exhibit No. RBD-1T at 4:14-16.

⁸¹ Dalley, Exhibit No. RBD-1T at 3:4-8.

⁸² Dalley, Exhibit No. RBD-1T at 5:16-18.

⁸³ Dalley, Exhibit No. RBD-1T at 5:1-4.

1 A: The Company states that due to the loss of revenue it has been unable to be
2 fully-compensated for stranded costs due to the permanent departure of large volume
3 customers to CREA over time. Further, the Company cites the risk of duplicate facilities
4 being installed at customer locations,⁸⁴ which raises concern that first responders could be
5 harmed if they cannot correctly identify which facilities are live and which have been
6 abandoned.

7 As a result, Pacific Power's proposals are intended to provide additional safeguards
8 requiring timely notice and compensation for stranded costs and facilities transferred,
9 removed, or abandoned associated with a customer's request to permanently disconnect
10 from the Company's system to be served by a competitive supplier.

11 **Q: Please describe your understanding of the current status of negotiations between the**
12 **Company and CREA.**

13 A: My understanding is that talks have come to a standstill, with communication about the
14 terms of such an agreement only by letter. In response to discovery, CREA says they have
15 sent two letters to Pacific Power's CEO seeking to improve relations and coordination
16 between the two companies, but has yet to receive a response.⁸⁵ Pacific Power, for its part,
17 observes that it has been unable to negotiate a service area agreement with CREA, even with
18 mediation services provided by an Administrative Law Judge, and that the informal
19 agreement was working adequately until a change in management at CREA.

20 **Q: Would a service agreement provide benefits in this situation?**

21 A: Yes. A robust service agreement that fully addresses terms that both parties can agree on,
22 has mutually agreeable terms for handling exceptions, and has terms that anticipate future

⁸⁴ Dalley, Exhibit No. RBD-1T at 13:13-15.

⁸⁵ Exhibit No. 14, CREA Response to Public Counsel Data Request No. 3, part a.

1 operating conditions or situations would be beneficial in this situation. One example of such
2 an agreement is the Service Area Agreement between PacifiCorp and Benton Rural Electric
3 Association (“Benton”). The PacifiCorp-Benton Agreement meets these basic criteria
4 because it states that its purpose is to avoid duplication of electric facilities by PacifiCorp
5 and Benton, establish procedures for service to new customers, and to study whether
6 services areas to be served exclusively by PacifiCorp or Benton should be established.⁸⁶

7 This Agreement states that service to any new customer or new load shall be provided by the
8 party having existing electric distribution facilities closest to the service entrance on the date
9 written application is made by the new customer or new load for such service, which meets
10 the criterion of pre-existing mutually agreeable terms to prevent duplication of electric
11 facilities. This same provision also anticipates future needs by allowing for the closest
12 utility to release the new customer tor new load to the other utility “for economic reasons.”⁸⁷

13 Finally, the term of this agreement extends to July 1, 2040 or until such time as this executed
14 agreement has been declared unlawful or unenforceable by the Commission, court order,
15 legislation, or regulatory action.⁸⁸

16 **Q: Does the PacifiCorp – Benton Agreement meet all of your requirements for being a**
17 **robust service agreement?**

18 **A:** The PacifiCorp-Benton Agreement deals with the most immediate issues of establishing
19 who should serve a new customer or new load by default and seeks to eliminate duplicative

⁸⁶ Exhibit No. KAK-16, Pacific Power’s Response to Commission Staff Data Request No. 4, Attachment WUTC-4, Exhibit 1, “Agreement for the Prevention and Elimination of Duplicative Electric Facilities between PacifiCorp and Benton REA”, dated July 29, 2015, Section 1, Purpose, page 7 of 9.

⁸⁷ Exhibit No. KAK-16, Pacific Power’s Response to Commission Staff Data Request No. 4, Attachment WUTC-4, Exhibit 1, “Agreement for the Prevention and Elimination of Duplicative Electric Facilities between PacifiCorp and Benton REA”, dated July 29, 2015, Section 3, Service to New Customers, page 8 of 9.

⁸⁸ Exhibit No. KAK-16, Pacific Power’s Response to Commission Staff Data Request No. 4, Attachment WUTC-4, Exhibit 1, “Agreement for the Prevention and Elimination of Duplicative Electric Facilities between PacifiCorp and Benton REA”, dated July 29, 2015, Section 5, Term and Termination, page 8 of 9.

1 facilities, which addresses the safety issue for first responders. In my experience, however,
2 there are two additional provisions that are missing from the PacifiCorp-Benton Agreement
3 that would make it a robust service agreement:

- 4 1) A term that specifies how the transfer of existing facilities from one utility to the
5 other utility by mutual agreement for economic reasons will be handled and who
6 pays for related facilities or transaction costs.
- 7 2) An early notice period for intent to renew or extend the term of the agreement by a
8 specified date and to allow for extension either on an annual basis or for a multi-year
9 term. The annual extension greatly enhances a service agreement because it provides
10 for continued operation under the agreement even when negotiations hit a road block
11 or are impacted by a change in management personnel at either utility.

12 These are features and protections that cannot be obtained by continuing to operate under an
13 informal agreement.

14 **Q: What is your understanding of the state’s policy with regard to service area (or**
15 **franchise) agreements?**

16 **A:** My understanding is that there is no requirement for a jurisdictional utility to have a service
17 agreement in place with neighboring utilities. According to Washington state statute, utilities
18 are “enabled” to enter into such agreements, but neither party to the agreement is required to
19 successfully negotiate a service agreement to have exclusive right to serve customers in a
20 specific geographic area.

21 In aid of the foregoing declaration of policy, any public utility and any
22 cooperative is hereby authorized to enter into agreements with any one or
23 more other public utility or one or more other cooperative for the designation
24 of the boundaries of adjoining service areas which each such public utility or
25 each such cooperative shall observe, for the establishment of procedures for

1 orderly extension of service in adjoining areas not currently served by any
2 such public utility or any such cooperative and for the acquisition or disposal
3 by purchase or sale by any such public utility or any such cooperative of
4 duplicating utility facilities, which agreements shall be for a reasonable
5 period of time not in excess of twenty-five years: PROVIDED, That the
6 participation in such agreement of any public utility which is an electrical
7 company under RCW 80.04.010, excepting cities and towns, shall be
8 approved by the Washington utilities and transportation commission.⁸⁹

9 **Q: What is your understanding of the state's policy with regard to duplication of electric**
10 **service facilities at a customer location?**

11 A: My understanding is that the Washington State Legislature policy discourages the
12 duplication of electric lines and services of public utilities and cooperatives for economic,
13 safety, and public interest reasons, but does not prohibit the practice.

14 The legislature hereby declares that the duplication of the electric lines and
15 service of public utilities and cooperatives is uneconomical, may create
16 unnecessary hazards to the public safety, discourages investment in
17 permanent underground facilities, and is unattractive, and thus is contrary to
18 the public interest and further declares that it is in the public interest for
19 public utilities and cooperatives to enter into agreements for the purpose of
20 avoiding or eliminating such duplication.⁹⁰

21 **Q: What do you conclude about the impact on stranded cost recovery of the two statutes**
22 **cited above?**

23 A: I conclude that customers in Washington who are served by utilities without the benefit of
24 an effective robust service area agreement in place, such as Pacific Power customers located
25 in Columbia and Walla Walla Counties, will continue to bear the burden of cost shifting due
26 to customer migration to neighboring utilities to some significant degree. This may be
27 expected to continue so long as three conditions persist:

28 1) The Company's expectation of flat growth in customer count and load remains true

⁸⁹ RCW 54.48.030.

⁹⁰ RCW 54.48.020.

1 over time;

2 2) The neighboring non-jurisdictional providers continue to have access to cheaper
3 sources of wholesale electric power; and

4 3) The Legislature leaves in place regulations that only enable rather than mandate
5 service agreements between jurisdictional utilities and rural electric associations and
6 cooperatives.

7 **Q: Turning your attention to low-income rate assistance and energy-efficiency programs,**
8 **do you know if rural electric cooperatives, such as CREA, offer such programs to their**
9 **customers?**

10 A: While I am not familiar with all rural electric associations and cooperatives in Washington, I
11 am aware of municipals elsewhere that offer such programs. I have specific knowledge
12 from responses to discovery in this proceeding that CREA does not offer such programs, but
13 customers are able to obtain similar assistance and benefits through other organizations.⁹¹ I
14 am also aware that Yakama Power offers its customers access to the energy efficiency
15 programs proposed by the Bonneville Power Administration.⁹²

16 **Q: Do you know have any concerns with CREA's acknowledgement that its customers**
17 **receive low-income rate assistance and energy-efficiency benefits by other means?**

18 A: Yes. Low-income rate assistance programs or energy-efficiency benefits achieved through
19 other means are not within CREA's control. Additionally, they cannot be compared to the
20 effort made by jurisdictional facilities of similar size to determine a greater effort could be

⁹¹ Exhibit No. KAK-15, CREA Response to Public Counsel Data Request No. 1, CREA Response to Pacific Power Data Request No. 18; <http://columbiarea.coop/content/rebate-offers>.

⁹² Exhibit No. KAK-17, Yakama Power Response to Public Counsel Data Request No. 1, page 2, <https://www.bpa.gov/EE/Policy/EEPlan/Pages/default.aspx> (Bonneville Power Association's description of their current plan and their proposed plan for 2016-2021).

1 made to help meet a statewide goal. For example, CREA acknowledges that it receives
2 payments from Blue Mountain Action Council (“BMAC”) to cover low-income members’
3 bills.⁹³ It is not clear, however, what selection process is used to determine eligibility or
4 how BMAC’s total quantity available for assistance is allocated across all eligible
5 customers, and there is no guarantee that BMAC funding will continue into the future.

6 **Q: Do Pacific Power’s customers receive low-income rate assistance through BMAC?**

7 A: Yes, Pacific Power’s federally funded Low-Income Home Energy Assistance Program
8 (LIHEAP) is administered by BMAC in Walla Walla, Northwest Community Action Center
9 in Toppenish, and the Opportunities Industrialization Center of Washington in Yakima. In
10 total, Pacific Power has distributed over \$2 million of energy rate assistance to its customers
11 for the period 2014-2016.

12 Jurisdictional utilities receive and distribute funding for low-income assistance from
13 a variety of sources, and eligibility to participate in assistance programs is often determined
14 under federal assistance programs and utility programs under the Commission’s jurisdiction.
15 Further Commission oversight of jurisdictional utilities occurs through requiring rates that
16 fund utility programs to be collected pursuant to tariff, which defines the rates charged to
17 customers and eligibility requirements of recipients. By contrast, CREA receives payment
18 only from BMAC, and is not obligated to account to the Commission for assistance provided
19 to low-income customers.

20 **Q: Are public utility entities required to meet the same energy-efficiency goals as investor-**
21 **owned utilities in Washington?**

22 A: It is my understanding that Washington has no public benefits funding to support energy-

⁹³ Exhibit No. KAK-15, CREA Response to Public Counsel Data Request No. 1, part a.

1 efficiency programs. Investor-owned utilities recover the costs of energy-efficiency
2 programs through tariff riders and program costs are reviewed annually before the
3 Commission.⁹⁴ Most publicly-owned utilities in Washington provide some funding for
4 energy-efficiency programs and services. Washington law as codified in Chapter 19.285
5 RCW requires each qualifying utility (those with more than 25,000 customers in
6 Washington) to pursue all available conservation that is cost-effective, reliable, and feasible.
7 Some publicly-owned utilities in Washington are qualifying utilities under this law. The
8 Commission has substantial oversight over energy-efficiency programs for investor-owned
9 utilities through the IRP process.

10 These rules require that the plan identify “the mix of energy supply resources
11 and conservation that will meet current and future needs at the lowest
12 reasonable cost to the utility and its ratepayers,” where lowest reasonable cost
13 means “the lowest cost mix of resources determined through a detailed and
14 consistent analysis of a wide range of commercially available sources. At a
15 minimum, this analysis must consider resource cost, market-volatility risks,
16 demand-side resource uncertainties, resource dispatchability, resource effect
17 on system operation, the risks imposed on ratepayers, public policies
18 regarding resource preference adopted by Washington state or the federal
19 government and the cost of risks associated with environmental effects
20 including emissions of carbon dioxide.”⁹⁵

21 The Commission does not exercise any oversight in relation to non-investor owned utilities’
22 conservation programs, while the Commission retains review and approval authority over
23 investor-owned utilities.⁹⁶

24 **Q: Please describe the energy-efficiency programs offered by CREA?**

⁹⁴ American Council for Energy Efficiency Economy (ACEEE), WASHINGTON STATE UTILITIES, CUSTOMER ENERGY EFFICIENCY PROGRAMS, ENERGY EFFICIENCY RESOURCE STANDARDS, <http://database.aceee.org/state/washington> (last updated July 2016).

⁹⁵ ACEEE, WASHINGTON STATE UTILITIES, CUSTOMER ENERGY EFFICIENCY, ENERGY EFFICIENCY AS A RESOURCE, <http://database.aceee.org/state/washington> (last updated July 2016).

⁹⁶ The department shall adopt rules concerning only process, timelines, and documentation to ensure the proper implementation of this chapter as it applies to qualifying utilities that are not investor-owned utilities. RCW 19.285.080(2).

1 A: CREA offers a range of rebates for customers who invest in or upgrade to more efficient
2 lighting fixtures and appliances and for weatherization for residential customers. For
3 commercial and industrial, as well as agricultural customers, CREA offers rebates for
4 lighting programs plus investment in more efficient drives and motors, plus irrigation
5 systems.⁹⁷ In response to discovery, CREA acknowledged that it spent \$793,028 on
6 conservation (including energy-efficiency) and achieved 28,576,106 kWhs in energy savings
7 over the last three years (2014 through 2016).⁹⁸

8 **Q: What concerns do you have with CREA’s energy-efficiency programs as it relates to**
9 **the customers who migrate from Pacific Power?**

10 A: I am concerned for two reasons. First, since publicly-owned utility energy-efficiency
11 programs receive limited oversight, it is difficult to be assured that CREA will continue to
12 offer the same or a larger size energy-efficiency program going forward. In fact, we do not
13 know from CREA’s response to discovery whether the savings ramp up or down over time
14 and we do not have a comparison of budget-to-actual spending and savings to evaluate
15 whether CREA’s program design is effective. As an example, CREA states that over the
16 past five years it has “paid out” an annual average of \$288,820 for energy efficiency.⁹⁹ It is
17 not clear whether these expenditures were cost effective or related to a specified
18 conservation target. Further we do not know the bill impact on CREA’s customers. The
19 concern is that, without transparency and oversight, customers may pay a significant
20 premium for programs that may not be cost effective. We do not know whether that is the
21 case with CREA’s customers, but these are metrics that are readily available for investor-

⁹⁷ Columbia REA, REBATE OFFERS, <http://www.columbiarea.com/content/rebate-offers>.

⁹⁸ Exhibit No. KAK-15, CREA Response to Public Counsel Data Request No. 1, parts b and c. CREA notes that it does not distinguish between conservation and energy-efficiency.

⁹⁹ Exhibit No. KAK-18, CREA Response to Pacific Power Data Request No. 12.

1 owned utilities that are subject to greater oversight by the Commission.

2 Second, I am concerned that continued migration of customers from Pacific Power to
3 CREA, in the absence of a service agreement, will erode support for Pacific Power's energy-
4 efficiency program, which is paid for through rate riders, and the magnitude of the rider will
5 increase as the burden to pay for the energy-efficiency program falls on the remaining
6 customers.

7 **Q: What benefits do you see accruing to customers from Pacific Power successfully**
8 **completing its negotiations for a service agreement with CREA?**

9 A: The benefits to all customers comes from reduced shifting of stranded costs to
10 remaining customers, who in this case are mostly residential, including low-income
11 customers. The continued funding of energy efficiency programs at current levels that offer
12 benefits to both participants and non-participants is a public interest benefit that would be
13 realized as well. Further erosion of energy-efficiency programs and increases in energy-
14 efficiency rate riders should be minimized.

15 **D. Safety Issues Raised by the Proposed Stranded Cost Recovery Fee.**

16 **Q: Please describe your understanding of the safety issue related to abandoned facilities**
17 **arising from a request for permanent disconnection.**

18 A: The informal arrangement between Pacific Power and CREA to serve customers based on
19 whichever utility's facilities were closer prevented safety and operational concerns and
20 duplication of facilities. Currently, Pacific Power believes that redundant facilities resulting
21 from customers disconnecting and taking service from CREA presents a major safety
22 concern and confusion.

23 **Q: Do you agree with Pacific Power's proposal for assessing safety conditions and**

1 **imposing liability on the departing customer and the replacement provider?**

2 A: No, I do not. Pacific Power’s proposal is too broad, and I believe it will not address the
3 primary safety concern, which is the construction of redundant facilities. The Company’s
4 proposed revisions seek only to transfer liability for abandoned facilities to disconnecting
5 customers at the Company’s sole discretion. Specifically, “the Company may abandon
6 some or all of the Facilities when, in the Company’s sole discretion, service may be
7 negatively impacted or safety issues may arise as a result of removal or purchase by the
8 departing customer.”¹⁰⁰

9 I agree with the Company that redundant facilities are a problem; at best, they are a
10 waste of resources and an eye sore and, at worst, they present safety concerns driven by
11 confusion, especially to first responders to a fire seeking to disconnect electric service.
12 However, it is unclear how preventing a departing customer from removing or purchasing
13 existing facilities eliminates the concern of redundant facilities. This revision appears rather
14 to be incenting their creation and perpetuating the problem.

15 While shifting the liability to the departing customer may not resolve this issue,
16 appropriate policies may mitigate the concerns. Such policies include:

- 17 • Evaluation the safety of service installations and subsequent removal or
18 abandonment in place.
- 19 • Consistency with National Electrical Safety Code and industry best practices.
- 20 • Assuring the safety of first responders.
- 21 • Confirming that each participant has complied with processes that ensure that the
22 change in service due to permanent disconnection has been rendered safe. It may be

¹⁰⁰ Pacific Power Tariff WN-U-75, Rule 6, Sheet No. R6.3.

1 necessary to include a meeting and signoff of the resulting disconnection to ensure
2 all parties have participated.

3 If these policies are followed then the liability that must be borne by the departing customer
4 and replacement provider should be no greater than they bore prior to the departure.

5 **VII. SUMMARY OF FINDINGS**

6 **Q: Please briefly summarize your findings.**

7 A: Pacific Power's proposed methodology to support a Stranded Cost Recovery Fee is not just
8 and reasonable. Further, wording used in the proposed revisions to Rule 6, Section I.1 and
9 I.2 are not consistent with principles of cost causation. The Company's presumption to have
10 sole discretion to determine Fair Market Value for facilities to be sold, and which facilities
11 are to be cited for removal or raising safety concerns, is also inconsistent with the principle
12 of cost causation. Pacific Power has not included contribution to low income rate assistance
13 programs or energy efficiency programs in its calculation of stranded costs.

14 **VIII. SUMMARY OF RECOMMENDATIONS**

15 **Q: Please summarize your recommendations.**

16 A: I recommend that the Commission deny Pacific Power's proposed revision to Rule 6 and
17 Schedule 300 as filed. If the Commission approves revisions to Rule 6 and Schedule 300, I
18 recommend that the Commission approve a different methodology to calculate the Stranded
19 Cost Recovery Fee based on:

- 20
- 21 • Calculating the net present value of non-net power costs over a six-year time frame;
 - 22 • Multiplying average revenue per customer times 3.0 for Residential customers and
23 4.5 for Non-Residential customers;
 - Setting a cap on the Stranded Cost Recovery Fee for Residential Customers equal to

1 \$4,138;

2 • Denying the Company's presumption of having sole discretion in favor of requiring
3 an independent review and appraisal of facilities being sold, transferred or
4 abandoned with each disconnection and removal request.

5 • Further modifications based on capturing the impact of contributions to low-income
6 rate assistance programs and energy efficiency programs would be appropriate.

7 **Q: Does this conclude your testimony?**

8 **A:** Yes, it does.