BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

V.

PUGET SOUND ENERGY,

Respondent.

DOCKETS UE-170033 & UG-170034 (*Consolidated*)

DIRECT TESTIMONY OF MICHAEL L. BROSCH (MLB-1T)

ON BEHALF OF

WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL,

PUBLIC COUNSEL UNIT

JUNE 30, 2017

DIRECT TESTIMONY OF MICHAEL L. BROSCH (MLB-1T)

DOCKETS UE-170033 and UG-170034 (*Consolidated*)

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I. INTRODUCTION / SUMMARY

Q: Please state your name and business address.

A: Michael L. Brosch. P.O. Box 481934, Kansas City, Mo. 64148-1934.

Q: By whom are you employed and in what capacity?

A: I am the President of Utilitech, Inc. and serve as a principal consultant in presenting the firm's work.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Public Counsel Unit of the Washington Attorney General's Office ("Public Counsel").

Q: Please describe your professional qualifications.

A: Please refer to Exhibit No. MLB-2 that I have prepared for this purpose.

Q: What exhibits are you sponsoring in this proceeding?

A: I am sponsoring Exhibit Nos. MLB-3 through MLB-10, as more fully described below:

Exhibit No.MLB-2	Michael Brosch Qualifications
Exhibit No. MLB-3	PSE Response to Public Counsel Data Request No. 62, with Attachment A
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Exhibit No. MLB-10 PSE Responses to Public Counsel Data Request No. 393, with Attachment A

Q: Have you previously testified in a rate case proceeding involving Puget Sound Energy before this Commission?

A: Yes. In Docket Nos. UE-060266 and UG-0602676, I testified on behalf of Public Counsel about regulatory policy matters regarding a PSE-proposed partial gas decoupling mechanism and in opposition to a PSE-proposed depreciation expense tracking mechanism, both of which were rejected by the Commission.[1]

Q: What is the purpose of your testimony in the current docket?

A: Public Counsel asked that I review and comment upon three regulatory policy recommendations being advanced by Puget Sound Energy ("PSE") in this proceeding:

1) PSE's proposal to continue electric and gas revenue decoupling, expanding the scope of decoupling to include certain defined fixed power costs and with certain modification to customer groupings, rate caps, and earnings sharing elements of decoupling.

2) PSE's proposal to have the Commission review and approve a new Electric Reliability Plan and an associated Electric Cost Recovery Mechanism ("ECRM") to collect incremental revenues from ratepayers for this Plan.

3) PSE's proposal to formalize procedures and scheduling to govern future Expedited Rate Filing ("ERF") applications, in place of more formal and comprehensive general rate cases.

[1] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-060266 & UG-060267 (*Consolidated)*, PSE 2006 Rate Cases, Order No. 08, at 16, 24. (Jan. 5, 2007).

In response to these proposals, my testimony (1) explains and supports the continuation of a revised form of the electric and gas revenue decoupling mechanisms, (2) recommends against piecemeal rate increases proposed in the Company's ECRM, and (3) recommends that the Commission not formalize ERF procedures in ways that would be harmful to ratepayers and the public interest.

In order to fully explain the recommendations in my testimony, I will first discuss the characteristics and the public interest advantages and disadvantages associated with traditional utility regulation and general rate cases. Then, I will explain how various forms of alternative regulation (such as revenue decoupling, multi-year rate plans, piecemeal cost recovery tracking mechanisms, and expedited rate adjustment mechanisms) impact these characteristics and change the risks, opportunities, and incentives normally associated with traditional regulation. Finally, I will address each of PSE's proposals in the context of this broader discussion, drawing conclusions and recommendations for consideration by the Commission.

Q: Please summarize your conclusions and recommendations with respect to PSE's proposed continuation of electric and gas decoupling in modified form.

A: I recommend that any continuation of decoupling for PSE's electric and gas businesses be modified to become "complete" decoupling, by removing the Revenue Per Customer ("RPC") feature of existing decoupling that grants automatic revenue increases to PSE as new customers are connected and served. I also recommend rejecting PSE's proposed changes to the decoupling Rate Test and Earnings Test, and I take no position with respect to PSE's proposed changes to the non-residential decoupling rate groups.

Q: Please summarize your conclusions and recommendations with respect to PSE's recommended Electric Reliability Plan and associated ECRM revenue increases.

A: I recommend that the Commission not accept responsibility for prioritizing PSE's reliability capital expenditures and, thus, not formally review and approve the Company's proposed Electric Reliability Plan. Additionally, I recommend rejecting the Electric Cost Recovery Mechanism, as it would provide improper piecemeal revenue increases to PSE to fund its proposed Electric Reliability Plan.

Q: Please summarize your conclusions and recommendations with respect to PSE's proposed formalization of Expedited Rate Filing ("ERF") procedures.

A: I explain why PSE has not justified its request to formalize ERF procedures and explain a number of problems with the ERF parameters that are proposed by the Company. If an ERF approach is formalized, it should:

1) Be limited to filings made within 12 months of a general rate case order,
2) Should permit the implementation of interim rates subject to refund if an adjudicated proceeding demonstrates that such rates are needed, and
3) Should provide adequate procedural intervals to permit intervention with discovery by concerned parties and effective review by Staff and intervening parties.

II. CHARACTERISTICS OF TRADITIONAL UTILITY REGULATION

Q: Since your testimony addresses various forms of alternative regulation of PSE, including decoupling, special cost recovery surcharge mechanisms, and expedited rate filings procedures, can you first describe the principal characteristics of traditional test year regulation?

A: Traditional regulation of energy utilities involves the conduct of formal rate cases, in which the utility selects a test year and presents a calculation of its desired revenue requirement, including operating expenses, depreciation and taxes, plus a rate of return applied to a rate base measure of invested capital. The key characteristics of traditional rate case regulation include:

- A **test year**, in which all of the components of the revenue requirement are holistically analyzed and quantified in a balanced and internally consistent manner with appropriate "matching" of costs and revenues.
- Utilization of regulatory lag as an **efficiency incentive**, by financially rewarding the utility for achieved cost reductions and punishing the utility when costs increase more rapidly than revenues between test years.
- Application of **regulatory rules** to the analysis of revenue requirement components, including prescribed adjustments, minimum filing requirements, and adherence to past rate orders and policies.
- A detailed **formal filing** with testimony and exhibits supportive of the asserted revenue requirement.
- Updated quantification of input data, employing a **holistic measurement** of changing revenue requirements.
- An opportunity for a **prudence review** of management actions or inaction that may have contributed to unreasonable recorded costs.
- **Procedural provisions** for discovery and critical analysis of test year data submitted by the utility, and to support issue development and litigation of disputed issues.

- **Comprehensive Review** of utility filings, discovery and submission of testimony and exhibits by Commission Staff and consumer intervenors.
- **Regulatory costs** are dedicated to support these more formal procedures.

The fundamental concept behind traditional utility regulation is that, in the absence of competitive markets to determine pricing for an essential public service, just and reasonable utility rates should be determined based primarily upon careful measurement of the utility's prudently incurred costs to provide such monopoly services.

Q: Does the PSE proposal seeking to formalize an Expedited Rate Filing procedure contradict some of the basic characteristics of traditional rate cases?

A: Yes. I will discuss this in a later section of my testimony. ERF formalization would necessarily compromise several of the important elements of traditional rate regulation, reducing the scope of required filings and greatly limiting possible discovery within a compressed schedule that likely precludes any serious consideration of management prudence, while providing no meaningful forum for effective intervention by concerned intervenors or the resolution of disputes.

Q: Would you agree that traditional utility regulation is often criticized as rewarding high costs with higher prices and encouraging excessive investment levels to earn even higher returns for shareholders?

A: Yes. However, electric and gas utilities are monopolies in nearly all markets they serve. In the absence of competitive market forces to control prices, regulators are left with few choices but to base utility prices upon the utility's underlying costs to provide, including a reasonable opportunity to earn a fair return. Setting utility prices in this way requires a program of comprehensive and effective regulation to protect the public interest from excessive utility costs and rates.

Q: Does traditional, test-year regulation cause public utility management to be completely indifferent about its cost levels?

A: No. An important element of traditional test period regulation is the incentive created for management to control and reduce costs, to maximize the opportunity to earn at or above the authorized return level between rate case test periods. Traditional test year regulation is not continuous regulation, because prices established in a rate case are fixed until they are changed in the next rate case. Changes in actual costs or sales levels between rate cases can increase or decrease a utility's profit levels before such changes can be translated into revised prices after a "next" rate case. This passage of time between rate cases, commonly referred to as "regulatory lag," serves as an efficiency incentive and moderates the counter-incentive that results when prices are based upon costs to serve.

Another beneficial characteristic of traditional test year regulation is the intensive focus upon utility operations and costs within a formal proceeding, in which Commission Staff and other interested parties can carefully examine or audit the components making up the revenue requirement. The potential for regulatory disallowance of excessive or imprudently incurred costs in such formal proceedings represents another form of an efficiency incentive to management.

Q: Are there any situations where the traditional test year ratemaking approach you describe should be modified?

A: Yes. There can be extraordinary circumstances where alternative mechanisms can supplement traditional test year ratemaking. One example is rate adjustment mechanisms to track changes in energy costs, such as fuel and purchased energy costs of electric utilities and purchased gas expenses of gas distribution utilities. I understand that this Commission, like many others, has adopted specialized cost recovery mechanisms for electric utility power costs and gas utility purchased gas expenses. Additionally, utilities can incur other large and volatile costs that are beyond the control of management, where traditional test year ratemaking may be incapable of producing reasonable results that properly balance the interests of the utility and its ratepayers. Finally, in Washington and several other states, revenue volatility has been mitigated by implementing various forms of revenue decoupling. These are types of incremental modifications to traditional regulation that are designed to remedy specific problems while maintaining the fundamental cost-based regulatory framework for other non-exceptional costs incurred to provide service.[2]

Q: Does the adoption of specialized regulatory mechanisms, such as revenue decoupling or cost recovery mechanisms for selected elements of the utility's overall cost of service, tend to reduce the incentives for management to attempt to grow revenues and reduce costs?

A: Yes. Revenue decoupling stabilizes utility revenues and earnings from variations caused by fluctuating weather and general economic conditions, while eliminating any perceived throughput incentive to utility management, where increased customer usage could otherwise increase profits. The "Revenue per Customer" form of decoupling used by PSE is particularly beneficial to utility profits, as it does more than stabilize the

[2] Beyond these types of incremental modifications to the traditional framework, some regulatory commissions have experimented with more comprehensive incentive-based regulation or performance-based regulatory plans. These can take the form of multi-year rate plans that seek to set regulated rates independent of changes in utility costs, in an effort to stimulate management efficiency by amplifying the regulatory lag incentive. PSE has not proposed a performance-based multi-year regulatory plan in the instant dockets.

Commission-approved revenue level by also locking in revenue growth proportionate to growth in the number of customers being served.

Adopting cost tracking mechanisms for a specific type of cost eliminates the regulated lag incentive that would normally serve to encourage efficiency and cost control between rate cases. If every dollar of a tracked type of cost is eligible for deferral and future rate recovery, management can afford to be less concerned about efficiency and the aggressive pursuit of cost containment for that type of cost and can be expected to focus attention on other areas of the business where earnings will be impacted by cost changes. In fact, if the pursuit of new efficiencies in connection to any tracked cost involves any significant risks or the incurrence of other costs that are <u>not</u> tracked, rational business behavior would discourage the pursuit of such efficiencies.

Q: Is there another, more fundamental problem created when isolated elements of the utility's revenue requirement are singled out for preferential rate treatment?

A: Yes. Utility costs and sales revenues tend to change continuously between traditional rate case test years. Some of the changes are favorable, such as productivity gains from deployment of improved technologies and the recently favorable capital market conditions that have allowed utilities to re-finance long-term debt at very low interest rates. Other changes are unfavorable, such as cost increases from general inflation upon wage rates and employee benefit costs. In rate cases, all of the elements used to determine revenue requirement, including all cost and revenue inputs, can be measured at a common point in time, which is the test year. The resulting forced "matching" of all inputs used to determine the revenue requirement allows the utility to recover prudently incurred cost increases prospectively, while insuring that ratepayers participate in any productivity gains and cost reductions that have occurred and are captured within test year results.

Q: Has this Commission recognized the importance of matching the many elements of revenue and costs in periodic utility rate cases, and <u>not</u> allowing piecemeal, single-issue ratemaking for only costs that the utility expects will grow between test years?

A: Yes. For example, in the 2006 PSE rate case I mentioned above, the Commission rejected the proposed depreciation tracker that the utility proposed as a remedy addressing regulatory lag. In its Order, the Commission stated:

> PSE argues it needs the depreciation tracker to address regulatory lag. According to the Company, it will invest $444 million and approximately $500 million in energy (electricity and natural gas) delivery infrastructure during 2006 and 2007 respectively. PSE contends that while customers will benefit from investments in this transmission and distribution plant as soon as the infrastructure is put into service, the Company will not recover the depreciation expense it incurs or any return on its invested capital until the conclusion of its next general rate case following the plant's in-service date.
>
> PSE undoubtedly recognizes regulatory lag is typical of rate base, rate of return ratemaking grounded in an historic test year adjusted for changes that are known and measurable at the end of that test year. Indeed, the circumstances of which PSE complains are simply an inherent part of the historic test period approach, which requires the application of certain fundamental ratemaking principles that we and many other regulators endeavor to apply consistently over time. In particular, we disfavor and typically avoid single-issue ratemaking and we are careful to preserve so far as is reasonable the "matching principle" that relies on our consideration of all revenues, costs, and adjustments in the context of a test year with a definite ending date. Thus, PSE asks us to approve a novel mechanism that departs from fundamental principles of ratemaking.
>
> PSE argues the Commission has in prior orders recognized it is appropriate to address earnings attrition when there is growing mismatch between revenues, expenses and rate base. According to the Company, it faces such circumstances due to regulatory lag and therefore its depreciation tracker or "known and measurable" rate base adjustment proposals are appropriate. PSE states it has performed detailed attrition

> studies that demonstrate earnings attrition, thus justifying the requested relief.
>
> It requires extraordinary circumstances to support a departure from fundamental ratemaking principles. In prior cases the Commission has required "a clear and convincing showing that the Company will be denied any reasonable opportunity to earn its authorized rate of return without extraordinary relief." We have considered the evidence PSE presented concerning attrition in some detail. Our analysis of the evidence leaves us unpersuaded that PSE will suffer earnings attrition as a result of not recovering depreciation on infrastructure investments it makes between rate cases.[3]

The Commission's conclusions regarding fundamental ratemaking principles, stated more than ten years ago, remain essential today in the face of continuing utility efforts to alter the regulatory framework in pursuit of improved earnings from regulated operations.

Q: Are you aware of any general criteria that you believe should be utilized to evaluate the need for special cost recoveries for certain utility costs?

A. Yes. Special cost recovery mechanisms should be approved <u>only</u> in instances where compelling circumstances justify departure from traditional test period review of all test year costs and revenues within rate case proceedings. Costs or revenue changes allowed to be deferred or tracked through a rider or cost recovery mechanism should generally have <u>all</u> of the following attributes to merit such exceptional and preferential rate recovery treatment:

1) Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases.

2) Beyond the control of management, where utility management has little influence

[3] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy* (PSE 2006 Rate Cases), Dockets UE-060266 & UG-060267, (*Consolidated)*, Order No. 08, ¶¶ 36-39 (Jan. 5, 2007) (footnote omitted).

over experienced revenue or cost levels.

3) Volatile in amount, causing potentially significant swings in income and cash flows if not tracked.

4) Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews.

5) Balanced, such that any known factors that mitigate cost impacts are accounted for in a manner that preserves test year matching principles.

In the testimony that follows, I will explain how these criteria argue for rejection of PSE's proposed Electric Cost Recovery Mechanism for selected reliability program investments.

Q: Should these criteria also be considered by regulators in considering the use of revenue decoupling mechanisms?

A: Yes. If decoupling is financially needed or is deemed necessary for public policy reasons, any decoupling mechanism under consideration should be designed to: (1) stabilize revenues from weather fluctuations and other variables that are outside the control of management, (2) use a methodology that is straightforward, readily audited, and properly balances all of the impacts upon revenues, and (3) properly captures revenue changes that are either financially favorable and unfavorable to the utility, in a balanced manner.

Unfortunately, the existing PSE decoupling mechanism is not reasonably balanced and is unduly complex. In the testimony that follows, I will explain a fundamental change to the Company's decoupling mechanism that should be adopted and then respond to other changes to the mechanism that are proposed by PSE witnesses.

III. EXPIRED MULTI-YEAR RATE PLAN

Q: Was PSE subject to traditional test period regulation in the years prior to filing the electric and gas rate cases in these dockets?

A: Prior to filing the pending general rate cases, PSE had not completed a traditional rate case for more than five years. The Company's last completed general rate case for its electric and gas utilities was in Dockets UE-111048 and UG-111048, which used a 2010 test year and culminated in the Commission's Order 08 issued on May 7, 2012.

Q: How was PSE's more recent rate plan created and approved by the Commission?

A: On February 1, 2013, PSE filed what it called an Expedited Rate Filing, seeking an increase in electric rates and a decrease in gas base rates in 2013 by selectively updating the 2010 financial information that was used to determine the revenue increases approved in the previous Order 08, so as to reflect year-ending June 30, 2012 financial data. PSE and the Northwest Energy Coalition ("NWEC") then jointly filed an Amended Decoupling filing on March 1, 2013, proposing to use the ERF to establish baseline decoupling rates that would then be escalated in a series of "K-factor" automatic rate increases of 3.0 percent annually for electric and 2.2 percent for natural gas. Other elements of this proposal included a 3.0 percent annual "soft cap" on rate increases, an earnings monitoring and sharing mechanism, and a commitment to not commence a new general rate case until at least 2015 and perhaps as late as 2016. The resulting rate plan was approved by the Commission in Order 07 issued in Dockets UE-121697 and UG-121705 on June 25, 2013.

Q: What were the Commission's goals in approving PSE's multi-year rate plan?

A: The Synopsis of Order 07 characterized the rate plan as comprised of, "several innovative ratemaking mechanisms that, together, fulfill the Commission's policy goal of breaking the recent pattern of almost continuous rate cases for Puget Sound Energy, Inc. ("PSE")."[4] The Synopsis also references decoupling of electric and natural gas rates as "promoting PSE's more aggressive pursuit of cost-effective conservation" by removing the "so-called throughput incentive" in a manner consistent with the Commission's 2010 Decoupling Policy Statement.[5]

The Synopsis characterized the annual K-factor annual rate increases as:

> a rate plan that will allow modest annual increases in PSE's rates while requiring that the Company not file a general rate increase before March 2016 at the earliest. This holds the promise of customers paying rates that are lower than might be the case under traditional approaches to ratemaking. The rate plan is designed to give an incentive to PSE to become more efficient and to implement cost-cutting measures that will promote its ability to earn its authorized overall rate of return.[6]

The Commission also mentioned the earnings test that, "requires PSE to share with customers on an equal basis any earnings that exceed its authorized return during the term of the plan" and that "annual rate increases are also capped at 3.0 percent." The Commission concluded that the "ERF is a one-time adjustment," and "[t]he rate plan expires by its own terms when PSE files its next general rate case as early as 2016. Decoupling will be allowed to continue only if it lives up to the Commission's expectations."[7]

Q: What are the primary challenges associated with the design of a multi-year rate plan?

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[4] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 (*Consolidated*), Order 07 Final Order Granting Petition, at i. (Jun. 25, 2013).
[5] *Id.*, at ii.
[6] *Id.*
[7] *Id.*, at iii.

A: The primary challenge involves accurately determining an adequate, but not excessive, amount of future revenue that is truly needed by the utility over multiple future years, in the absence of any reliable estimates of future operating and financial conditions that will be faced by the utility. Significant uncertainties surround future conditions in financial and labor markets, the potential for changes in tax or environmental laws, the difficulty in predicting future inflation and productivity levels, and the myriad of other important assumptions required to develop long-range forecasts that make it very difficult to find consensus forecasts that are acceptable to all the parties involved in utility regulation. Periodic rate cases provide a forum to consider and adjust for changed conditions— a forum that is suspended during a multi-year rate plan.

Of course, investor owned utilities are for-profit businesses, where management has a fiduciary responsibility to shareholders to maximize profit. For any multi-year rate plan to be attractive to utility management, the projected stream of future revenues and profits must be clearly better than is achievable under continued traditional regulation, where rate cases can be filed whenever needed. Opting into a multi-year rate plan with a rate case moratorium represents a poor business decision for management unless shareholders are clearly better off financially under such a plan. This situation leaves the regulator in a difficult position, facing utility management with superior knowledge of expected future operating and financial conditions, needing to offer a future revenue stream that is attractive enough for utility management to accept the risks associated with committing to a rate case moratorium. Multi-year rate plans are relatively uncommon, because of the risk that ratepayers will "overpay" for the rate case moratorium they receive in return. Indeed, this appears to be what happened under the expiring PSE rate plan.

Another concern arises from the expanded regulatory lag incentive for cost control during any multi-year rate plan, where excessive cost reductions could compromise service reliability, responsiveness to customer needs or public safety. To combat these issues, regulators may attempt to develop performance incentive measures ("PIMs") to track and reward or penalize changes in service quality. In fact, PSE operates under a Service Quality Performance program that includes specific service quality and customer service performance standards and penalties for the failure to comply with annual standards. Ms. Alexander discusses this program and PSE's proposal to make certain changes to this program in her Testimony on behalf of Public Counsel.

Q: Did PSE realize significant revenue increases throughout the term of the expired rate plan?

A: Yes. As noted previously, after the initial ERF rate increase, the rate plan pre-approved annual rate increases over the next four consecutive years through an upward K-factor adjustment to the authorized revenue-per-customer. Beyond these specifically authorized revenue increases, PSE also realized substantial new revenues from customers that were added each year since the inception of the rate plan because PSE is allowed to keep for the sole benefit of shareholders new revenues resulting from customer growth under the "revenue per-customer" ("RPC") form of decoupling that was approved as part of the rate plan. From July 2013 through December 2016, the pre-approved K-factor rate adjustments and additional customer growth caused PSE to realize cumulative electric revenue increases totaling $197 million and cumulative gas margin revenue increases totaling $128 million. I have summarized the rate plan revenue increases experienced by the Company, based upon PSE's response to Public Counsel Data Request No. 62, which I have included in Exhibit MLB-3:

Figure 1:

Electric Revenue Increases

	K-factor	New Customers	Total
2013	$8,608,663	$(1,595,522)	$7,013,141
2014	37,437,389	(1,311,229)	36,126,160
2015	57,636,291	4,716,181	62,352,472
2016	79,085,607	12,738,212	91,823,819
	$182,767,951	$14,547,641	$197,315,592

Gas Revenue Increases

	K-factor	New Customers	Total
2013	$4,038,814	$2,247,840	$6,286,654
2014	18,202,139	8,380,616	26,582,756
2015	27,933,490	12,346,038	40,279,529
2016	38,150,623	16,996,875	55,147,498
	$88,325,067	$39,971,370	$128,296,436

The electric revenue increases from New Customers would have been much higher but for approximately 18,000 Jefferson County electric ratepayers that left PSE's system in

April of 2013 when the Jefferson County PUD started serving these customers.[8]

Q: Why do the annual revenue increase amounts in your Figure 1 increase significantly in the later years of the rate plan?

A: Both elements of PSE's revenue growth have compounding cumulative impacts. The K-factor rate increases in year three are stacked on top of the prior year's allowed K-factor increases. Similarly, the revenue growth caused by new customer additions, under the RPC form of decoupling allowed PSE to retain for shareholders the revenues from new customers added in year one, plus year two, plus year three, causing this source of new revenues to become ever larger under the rate plan.

Q: Did PSE's relatively high returns during the rate plan years approach or rise above the Commission's authorized levels of Return on Equity ("ROE") for the Company?

A: Yes. PSE witness Mr. Daniel Doyle presents Tables 1 and 2 in his direct testimony showing strong and steadily improving ROE results for both the electric and gas utility operations, with a sharing of excessive earnings in both 2015 and 2016 for the benefit of electric and gas ratepayers. When the year-ending June 2016 returns in Tables 1 and 2 are updated, reflecting the Company's 2016 full calendar year earnings as stated in the Commission's Basis Reports (CBRs), 2016 earnings are somewhat higher for the electric operations and somewhat lower for gas operations, than is depicted originally by Mr. Doyle in his direct testimony, but still above Commission-authorized levels for both utilities.[9]

Q: What do the Company's excessive earnings in 2015 and 2016 tell us about the

[8] *Id.*

adequacy of the K-factor and RPC decoupling revenue increases that were authorized by the Commission at the inception of the rate plan?

A: These results imply that the rate plan K-factor revenue increases, when combined with customer growth-driven new revenues from the Company's RPC form of decoupling, may have been larger than necessary in the last two years. Said differently, if electric and gas traditional rate cases had been filed earlier than the pending PSE rate filings, such filings may have more effectively captured PSE's declining costs in 2015 for the benefit of ratepayers than occurred under the rate case moratorium. In addition, the Company enjoyed overly generous K-factor and RPC decoupling revenue increases in 2016. These results also imply that PSE was able to manage its expenses and capital investments well within the boundaries of the K-factor and RPC decoupling revenue growth, through a combination of management efforts and an environment of highly favorable capital market, income tax deferral, and general inflation conditions.

Q: Do the Company's witnesses claim credit for management cost savings efforts as the cause for PSE's recent excess earnings?

A: Yes. PSE witnesses have focused their testimony on claims of various management cost savings initiatives to explain the Company's recent excessive earnings. For example, Mr. Doyle devotes an entire section of his testimony to what he calls a "cost management and efficiency update" and he claims,

> [I]n the final analysis, it is clear that PSE's approach to managing and constraining operating expenditures, and more importantly harvesting cost efficiencies, contributed significantly to the dual objectives of providing service at a reasonable price to customers and adequately rewarding both

[9] PSE response to Public Counsel Data Request No. 66, Supplement One, Attachment A shows CBR normalized results of operations yielding an 8.06 percent and 7.93 percent overall rate of return on rate base for electric and gas operations, respectively, versus 7.77 percent and 8.44 percent in Tables 1 and 2.

> debt and equity investors to maintain adequate access to capital markets at reasonable cost.[10]

However, the favorable capital market opportunities cited by Mr. Doyle that enabled PSE to refinance its debt to save "…$19.3 million in annual pretax interest costs" cannot fairly be attributed solely to measures taken by management.[11] If not for extraordinarily low yields recently available in the capital markets, these savings would not have been possible.

Similarly, the "bonus depreciation elections" referenced by Mr. Doyle were enabled by federal tax legislation rather than the Company's management, and were also claimed by every other utility I have studied where these tax deductions were available; savings that are reasonably expected of any reasonably prudent utility tax management personnel.[12]

Q: Has the Company been able to reduce the rate of growth in operating expenses during the term of the rate plan?

A: Yes. According to PSE witness Ms. Barnard, "…there has been a slowing in operating expense growth compared to the 2006 to 2011 period for both gas and electric operations; however, due to changes in the allocation of common costs between the two services, the growth in electric operation expenses is higher and natural gas is lower."[13] Ms. Barnard then sponsors Table 2 and Table 3 to show Electric Operating Expense per Customer Trending and Natural Gas Operating Expense per Customer Trending from calendar year 2011 through the test year amounts. The compound rate of growth in electric expenses is

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[10] Direct Testimony of Daniel A. Doyle, Exh. DAD-1T, at 28, ll. 5-9.
[11] Doyle, Exh. DAD-1T, at 29, ll. 9-10.
[12] *Id*., at 28-31.
[13] Direct Testimony of Katherine J. Barnard, Exh. KJB-1T, at 8, ll. 15-18.

3.2 percent over this period of time, while gas expenses declined slightly at a compound growth rate of negative 0.3 percent. On a combined electric and gas utility basis, Ms. Barnard's Table 1 shows the Company's expenses have increased at a compound growth rate of 2.0 percent since 2011.[14]

Q: Should PSE's expenses be evaluated on a "per customer" basis as presented in Ms. Barnard's Tables 1, 2 and 3?

A: No. Most of PSE's costs are fixed costs that do not vary with the number of customers being served. There is no justification to divide total expenses by PSE's growing customer count in order to dilute the apparent rate of expense growth, as presented in Ms. Barnard's Tables 1, 2, and 3. I will explain which of the Company's costs are actually treated as customer-driven costs that may vary proportionately with the number of customers being served in a later section of this testimony.

Q: If we compare historical growth in PSE's expenses to a widely used national inflation index across the periods presented in Ms. Barnard's Tables 1, 2, and 3, do the Company's expense trends compare favorably?

A: No. PSE's expenses have actually grown faster than overall inflation, as measured by the Gross Domestic Product Price Index ("GDPPI"). This index is an economy-wide measure of overall price levels. The Hawaii PUC currently uses GDPPI as an overall constraint upon annual revenue adjustments allowed through the Rate Adjustment Mechanism element of the decoupling mechanism applied to Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company, Ltd.

Using information from Ms. Barnard's Tables 1, 2 and 3, PSE's expenses,

[14] Barnard, Exh. KJB-1T, at 9.

compared to GDPPI inflation trends, yields the following comparison:

Figure 2:

	2011	2012	2013	2014	2015	Test Year June 2016	Compound Growth %
Change in GDPPI by Year:							
BEA Reported Values	103.315	105.22	106.917	108.838	109.999	111.451	**1.7%**
Change Percentage		1.8%	1.6%	1.8%	1.1%	1.3%	
PSE Electric Expenses	$ 235,948,974	$ 244,438,664	$ 255,849,409	$ 270,161,178	$ 262,118,931	$ 272,188,472	**3.2%**
Change Percentage		3.6%	4.7%	5.6%	-3.0%	3.8%	
PSE Gas Expenses	$ 130,171,206	$ 129,510,591	$ 131,760,339	$ 135,426,809	$ 126,839,840	$ 128,669,004	**-0.3%**
Change Percentage		-0.5%	1.7%	2.8%	-6.3%	1.4%	
PSE Combined Expenses	$ 366,120,180	$ 373,949,255	$ 387,609,749	$ 405,587,987	$ 388,958,771	$ 400,857,476	**2.0%**
Change Percentage		2.1%	3.7%	4.6%	-4.1%	3.1%	

When compared to GDPPI, the trend in PSE's actual expenses and management's ability to control such expenses below the general level of inflation is not exemplary.

Q: Are operating expenses the only determinant of utility revenue requirements?

A: No. The revenue requirement is driven by the level of new capital investment that contributes to rate base growth, as well as changes in the cost of capital and changes in billing determinants (customer and energy sales volumes).

Q: Do the base rate increases now being proposed by PSE suggest that management has been able to permanently reduce ongoing expenses and investment levels, in response to the cost control incentives provided by the expired rate plan?

A: No. The Company's request for proposed jurisdictional base rate increases of 7.3 percent for electric operations and 5.2 percent for gas operations, as summarized by Mr. Piliaris,[15] suggest that permanent and ongoing improvements in PSE's cost structure have not been achieved by management. The Company-proposed base rate changes in these dockets continue to exceed the general rate of inflation, as measured by GDPPI.

Q: Is it possible that PSE was allowed more revenue increases than were necessary during the term of the rate plan, given the size of the K-factor and the RPC decoupling customer growth revenue increases previously mentioned in your testimony?

A: Of course. The Company's earnings growth during the term of the rate plan and its recently excessive earnings subject to sharing could have been caused by only two factors: excessive revenue levels or declining costs. Earnings represent the residual amount of money left after revenues are reduced by the utility's overall cost of service. As noted above, management is claiming that reductions in the rate of annual increase in PSE's overall expenses should be accepted as the reason for higher earnings. However, excessive K-factor rate increases and excessive RPC customer growth revenue increases also contributed to excessive earnings. Unfortunately, ratepayers were allowed only a 50 percent share of any excessive rates they paid during the rate plan.

Q: How does PSE characterize the results of the expiring rate plan?

A: According to Mr. Doyle,

> [i]n addition to the mitigation of the continuing effects of attrition and regulatory lag, the rate plan achieved other important policy objectives. First, the combined effects of the expedited rate filing and the K-factor annual increases allowed PSE to avoid filing at least one and possibly two general rate cases during the plan period. From PSE's perspective, this achieved the Commission's objective of reducing the burden of frequent general rate cases on its regulatory docket along with the time, energy, and costs that accrues to all parties that participate in general rate case proceedings.[16]

He also touts a "more predictable and gradual increase to PSE's base rates as compared to increases resulting from general rate cases, which tend to be larger and less predictable

[15] Supplemental Testimony of Piliaris, Exh. JAP-34T, at 12 and 14, Tables 1 and 2.

from a customer perspective."[17] Mr. Doyle then separately describes the results of decoupling in a separate section of his testimony, concluding with the observation, "PSE is satisfied that the decoupling mechanism has operated well in practice."[18]

Ms. Barnard relies upon her expense trend analysis, discussed above, to conclude, "there has been a slowing in operating expense growth compared to the 2006 to2011 period" and "…through the earnings sharing mechanism in place during the rate plan period, customer received 50 percent of any earnings above PSE's authorized rate of return."[19]

Q: Is it possible to know whether ratepayers would have been better or worse off today without the expired rate plan and under a continuation of traditional regulation of PSE through general rate cases?

A: Probably not. In general, multi-year rate plans that contain rate case moratoria have the effect of amplifying the regulatory lag incentive for management efficiency. Management may respond to this incentive by deferring costs that are discretionary in the short term into future periods, so that shareholders and customers can "share" in the resulting excess earnings. However, if higher costs <u>after</u> the deferral period then serve as a basis for large traditional rate increases in a general rate proceeding at the end of the rate plan, there is no ongoing benefit for customers. Thus, ratepayers may be worse off, having only "shared" the temporary cost savings with the utility. Only structural changes in the utility's organization and business processes can be expected to produce more

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[16] Doyle, Exh. DAD-1T, at 5, ll. 7-14.
[17] Doyle, Exh. DAD-1T, at 5-6.
[18] *Id*., at 5-6, 7-13, regarding decoupling.
[19] Barnard, Exh. KJB-1T, at 8, ll. 15-16, Exh. KJB-1T at 10, ll. 12-13.

permanent and continuing benefits that may be "captured" for ratepayer benefit in general rate cases.

Q: After concluding that the expiring rate plan was successful in meeting its goals and that decoupling has operated well in practice, has PSE proposed any new multi-year rate plan or continuation of decoupling in its present form?

A: Remarkably, no new multi-year rate plan has been proposed by PSE. Instead, the Company has proposed a different package of regulation, consisting of the following principal elements:

- Continuation of the RPC form of decoupling that provides the utility with automatic annual electric and gas revenue increases resulting from customer growth, but modified with respect to customer groupings, earnings sharing, and rate impact testing.
- Expansion of the revenue base subject to RPC decoupling, so that automatic annual revenue increases resulting from customer growth are also applied to the recovery of fixed power costs.
- No base rate case moratorium.
- Liberalization of earnings sharing procedures, so that normalization adjustments are no longer included, shifting the risks of weather and power cost fluctuations away from shareholders and toward ratepayers.
- Creation of a new surcharge mechanism to recover, on a piecemeal basis, return and depreciation costs for specifically targeted Electric Reliability Plan investments.
- Formalization of Expedited Rate Filing ("ERF") procedures that would allow base

rates to increase quickly, and with minimal intervention and regulatory oversight, or whenever the Company's management concludes that a financial need exists for higher base rates.

My remaining testimony will address each of these PSE proposals.

IV. DECOUPLING AND CUSTOMER GROWTH

Q: What are the claimed benefits of revenue decoupling for electric and gas utilities?

A: Proponents of decoupling often claim several benefits are created by revenue decoupling. These include:

- Stabilization of utility revenues and earnings, reducing fluctuations caused by weather, changing economic conditions, customer conservation effects, and the influx of distributed energy resources ("DER") including photovoltaic, wind generation, and other forms of customer self-generation.
- Reduced utility operating risks and lower costs of capital and due to the shifting of revenue volatility risks from shareholders to ratepayers.
- Removal of a so-called throughput disincentive, which may cause utility management to be less supportive of customer conservation measures or interconnecting and serving DER than is desirable as a matter of public policy.
- In instances where decoupling deferral amounts are rapidly collected or returned to ratepayers, decoupling can stabilize and moderate customers' bills during periods of severe or mild weather.

Consideration of these claims has caused some regulatory jurisdictions to adopt a form of decoupling as part of the regulatory framework that is employed, often tailored, to the unique operational concerns and legal framework extant in the state.

Q: Has the Washington Commission addressed these policy issues within prior rate orders and in a general policy statement?

A: Yes. In its 2010 Decoupling Policy Statement, the Commission referenced some of these asserted benefits. The Commission at that time was more circumspect regarding the possible adoption of full decoupling, stating:

> *Discussion.* Though we recognize the potential benefits to ratepayers, adoption of full decoupling gives us some pause for two reasons. First, relatively few other state commissions have adopted any form of decoupling for electric utilities, and only some of those mechanisms were full decoupling mechanisms. So, adopting such a mechanism for Washington's electric utilities would put the Commission in the company of a relatively small minority of commissions nationwide. This means that the Commission does not yet have the benefit of lessons learned in other jurisdictions as it develops and refines a full decoupling mechanism.
>
> Second, with full decoupling comes a concern that, by eliminating the risk of recovery of declines in revenue, combined with an energy cost recovery mechanism that reduces an electric utility's financial risk due to changes in power costs, the utility could lose some of its incentive to manage the company in a manner that constantly looks to reduce costs. Indeed, some experts in the theory and practice of regulation caution commissions to engage in regulation that constantly provides incentives for a utility to cut costs. Such prudent actions on the part of the utility serve to benefit the utility as well as, in the long run, the ratepayers. Because of our lingering concerns regarding possible reduced incentives for companies to manage in an efficient manner, we will require evidence and argument from the parties on this issue in the context of a request for a full decoupling mechanism.
>
> Nevertheless, while a close call, we believe that a properly constructed full decoupling mechanism that is intended, between general rate cases, to balance out both lost and found margin from any source can be a tool that benefits both the company and its ratepayers. By reducing the risk of volatility of revenue based on customer usage, both up and down, such a mechanism can serve to reduce risk to the company, and therefore to investors, which in turn should benefit customers by reducing a company's debt and equity costs. This reduction in costs would flow through to ratepayers in the form of rates that would be lower than they otherwise would be, as the rates would be set to reflect the assumption of more risk by ratepayers.

> *Description of Mechanism.* In the context of a general rate case, the Commission will consider a full decoupling mechanism for electric and natural gas utilities, which will allow a utility to either recover revenue declines related to reduced sales volumes or, in the case of sales volume increases, refund such revenues to its customers. Revenue recovery by the company under the mechanism will be conditioned upon a utility's level of achievement with respect to its conservation target. A utility's request for a full decoupling mechanism must be made in its direct testimony of its rate case filing, and include, at a minimum, the following elements:
>
> > *1. True-up Mechanism.* Where, between general rate cases, customer use by class deviates either higher or lower from that determined by the Commission when setting rates, a utility can seek an annual true-up of revenue attributed to each affected class of customer.
> >
> > 2. *Impact on Rate of Return.* Evidence evaluating the impact of the proposal on risk to investors and ratepayers and its effect on the utility's ROE.
> >
> > 3. *Earnings test.* A proposed earnings test to be applied at the time of the true-up.
> >
> > 4. *Accounting for Off-System Sales and Avoided Costs.* A description of the method the company intends to use to determine the financial benefits associated with off-system sales or avoided costs attributable to the utility's conservation efforts and then to net these benefits against the true-up provided in this mechanism.[20]

Q: Were some of claimed benefits from decoupling that you listed above also referenced by the Commission in Order 07 approving the decoupling elements of the PSE rate plan?

A: Yes.[21] However, in its Order 07 the Commission found that:

> the record in this proceeding does not support an adjustment to PSE's equity return. This does not necessarily lay the matter to rest. The Commission may yet, on an adequate record in a future proceeding, find that such an adjustment is warranted to compensate for the shift of risks

[20] *Wash. Utils & Transp. Comm'n Investigation into Energy Conservation Incentives.* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, ¶¶ 25-29 (Nov. 4, 2010).

[21] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 (*Consolidated*), Order 07 Final Order Granting Petition, at 42-52. (Jun. 25, 2013).

> from PSE to its ratepayers that unquestionably is a result of implementing decoupling.[22]

On this point, I would encourage the Commission to insist upon accounting for the risk shifting impacts of any continuation of decoupling for PSE as a reduction to the allowed ROE, to ensure that ratepayers participate in such benefits.

Q: Was there another decoupling issue raised at the inception of the PSE rate plan that the Commission stated its intent to revisit in the future within Order 07?

A: Yes. The issue was captioned "found margin" in Order 07 and it arises from the use of the RPC form of decoupling that was proposed by PSE and NWEC. Ultimately, this form of decoupling was adopted as part of the PSE rate plan.

Q: What is "found margin" in the context of decoupling?

A: In the Decoupling Policy Statement quoted above, "found margin" was indicated to be important within the Commission's statement, "we believe that a properly constructed full decoupling mechanism that is intended, between general rate cases, to balance out both lost and found margin from any source can be a tool that benefits both the company and its ratepayers."[23] Making reference to this provision in the Policy Statement, Order 07 approving the rate plan noted that several parties were recommending that PSE's proposed decoupling plan, "…be modified to incorporate any found margin associated with growth in customer count against the decoupling balancing account."[24]

Q: Why is this an important issue?

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[22] *Id*., at 49.

[23] *Wash. Utils & Transp. Comm'n Investigation into Energy Conservation Incentives,* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, ¶ 27 (Nov. 4, 2010).

[24] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 (*Consolidated*), Order 07 Final Order Granting Petition, at 51 (Jun. 25, 2013).

A: If the intent of decoupling is to completely break the link between sales volumes and utility revenues, all of the drivers of revenue change must be recognized. The drivers of utility sales volume and revenue changes typically fall into three general categories:

1) Fluctuations in sales caused by weather, changes in economic conditions and any shifts in large commercial customer demand.

2) Systematic reductions in sales through time caused by utility sponsored conservation programs, customers' own conservation efforts, improvements in appliance efficiency, improved building standards, and the influx of distributed energy resources.

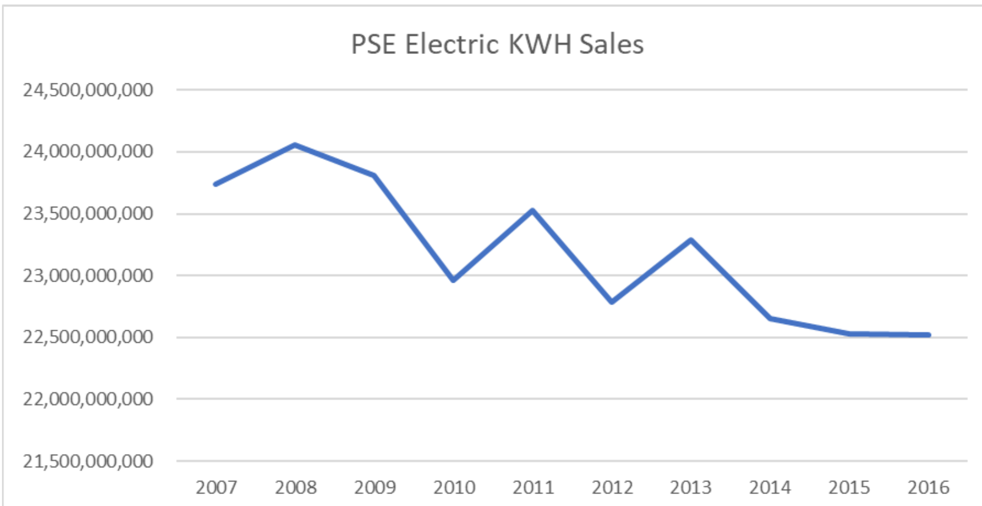
3) Systematic growth in sales through time caused by the continuous addition of new customers, for those utilities like PSE that benefit from significant customer growth.

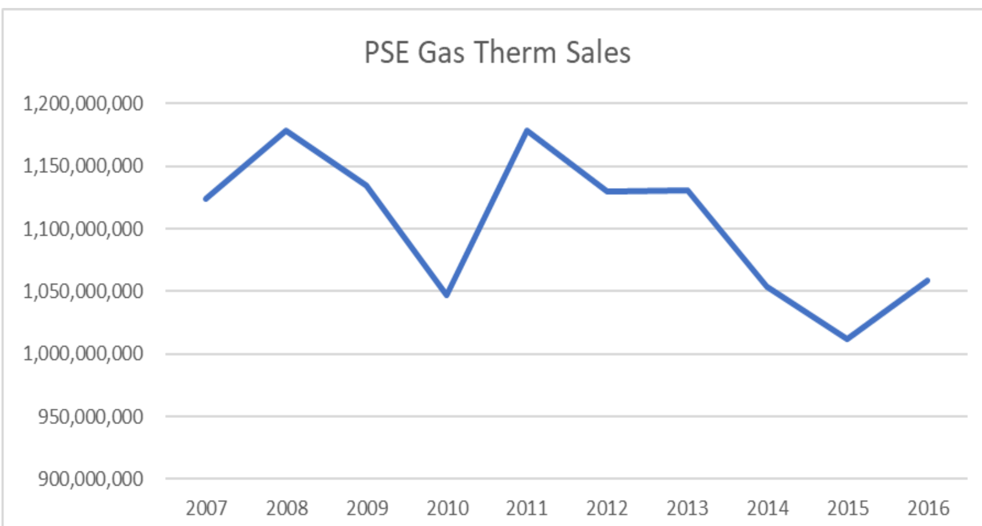
However, the RPC form of decoupling within the expiring PSE rate plan accounts for only the first and second categories listed above. This has the unfortunate effect of leaving all of the sales and revenue growth caused by adding new customers for the sole benefit of PSE shareholders, while charging ratepayers for the combined impact of categories 1 and 2.

Q: When all three categories of sales drivers you identified are considered, is there any discernable overall trend in PSE electric and gas sales volumes over the past decade?

A: Yes. In addition to the annual fluctuations arising from category one factors described above, there is an observable slight downward trend in PSE electric and gas sales volumes over the past decade, indicating that conservation effects (category two) are slightly exceeding customer growth effects (category three). The following scaled graphs depict these effects over the period 2007 through 2016, using data provided by PSE:[25]

Figure 3:





The Company's electric and gas sales volumes in 2016 are less than six percent lower than reported sales volumes nine years earlier, in 2007.[26] Unfortunately, the Company's

[25] PSE Response to WUTC Staff Data Request No. 266 and 268.

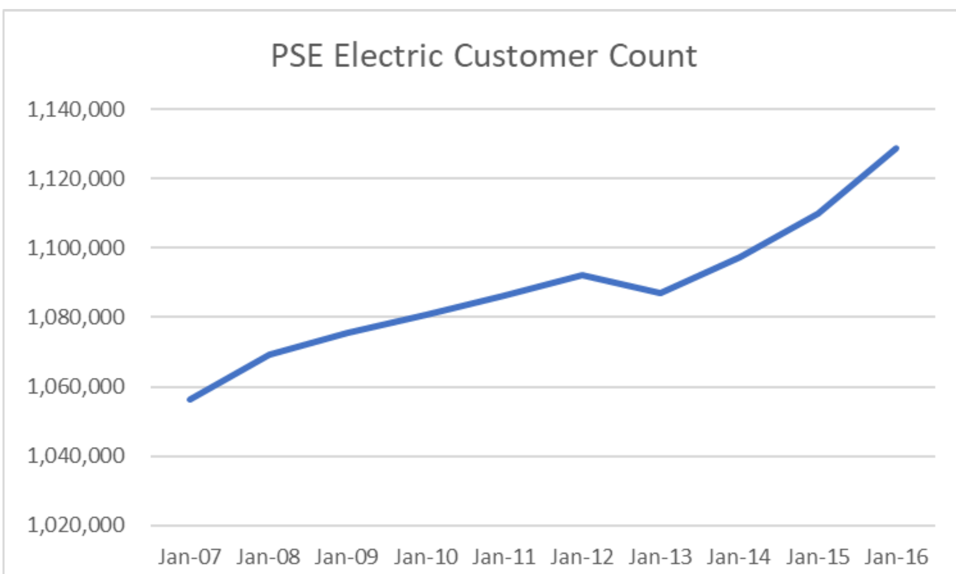
[26] PSE Response to WUTC Staff Data Request 266, Attachment A shows PSE electric sales of 22.5 GWH in 2017, compared to 23.7 GWH in 2007, a decline of 5.1 percent. PSE Response to WUTC Staff Data Request 268, Attachment A shows PSE gas sales of 1058397,439 therms in 2017, compared to 1,124,291,607 therms in 2007, a decline of 5.9 percent.

RPC form of decoupling considers only the effects of category one and category two conservation trends, ignoring the offsetting customer growth benefits, so they accrue for the sole benefit of the utility and its shareholders.

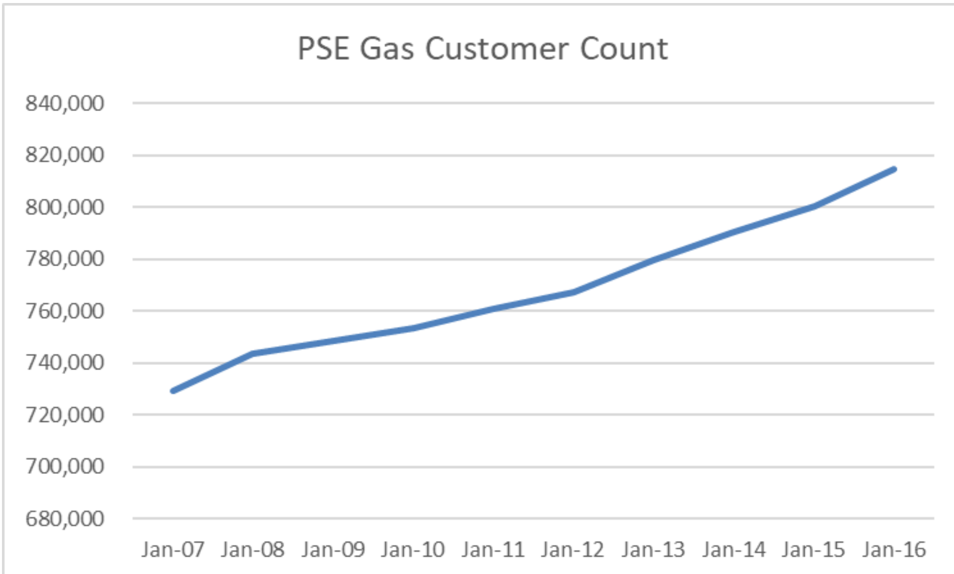
Q: How significant is customer growth for PSE?

A: According to PSE witness Ms. Gilbertson, "PSE has added 45,058 new gas customers over the course of five years, yielding a total of 6 percent growth in that time period."[27] With respect to the electric business, she states, "[s]ince 2011, PSE has added 23, 760 new electric customers, averaging 0.5 percent growth per year (through 2015) and forecasts 1.2 percent growth over the next few years."[28] The Company's historical growth in customers served can be observed in the following scaled graphs:[29]

Figure 4:



[27] Direct Testimony of Booga K. Gilbertson, Exh. BKG-1T, at 11.
[28] *Id*., at 23.
[29] PSE Response to WUTC Staff Data Requests Nos. 265 and 267.



Notably, the Company expects continuing growth in the number of electric and gas customers it serves.

The following presents actual 2016 and forecasted customer count data:[30]

Figure 5:

Annual Average PSE Customers: Actuals 2016, F16 Forecast 2017-2037			
Type	Year	Electric	Gas
Actual	2016	1,119,703	807,450
Forecast	2017	1,130,132	816,668
Forecast	2018	1,144,022	827,989
Forecast	2019	1,158,927	839,420
Forecast	2020	1,174,378	850,817
Forecast	2021	1,189,849	862,222

[30] PSE Response to Public Counsel Data Request No. 68

Forecast	2022	1,205,426	873,665
Forecast	2023	1,221,076	885,179
Forecast	2024	1,236,769	896,746
Forecast	2025	1,252,512	908,368
Forecast	2026	1,268,280	920,067
Forecast	2027	1,284,062	931,857
Forecast	2028	1,299,827	943,756
Forecast	2029	1,315,555	955,780
Forecast	2030	1,331,229	967,941
Forecast	2031	1,346,828	980,260
Forecast	2032	1,362,345	992,773
Forecast	2033	1,377,798	1,005,475
Forecast	2034	1,393,194	1,018,420
Forecast	2035	1,408,563	1,031,631
Forecast	2036	1,423,946	1,045,132
Forecast	2037	1,439,362	1,058,942

This information reflects PSE's expectations that customer growth will continue at a rate exceeding one percent per year, well into the future for both its electric and gas utility business.

Q: Do new customers added by PSE contribute new revenues that should be considered "found margin" as the term was used in the Commission's Decoupling Policy Statement?

A: Yes. Earlier in this testimony, I explained the problems created by single-issue or "piecemeal" ratemaking and the importance of matching all elements of a utility's changing revenue requirement when determining the revenue requirement. Decoupling is single-issue ratemaking that tracks changes in sales volumes between test years. If decoupling is allowed to continue in the RPC form that is preferred by the utility, the "matching" that is essential as a matter of ratemaking policy is destroyed. Customer growth that persistently increases PSE's sales volumes should be considered as an important offset to the conservation trends that are reducing electric and gas sales with all of these trends captured within a "complete" form of decoupling applied prospectively.

A. RPC Decoupling Should Be Replaced with Complete Decoupling

Q: If decoupling is extended for PSE, what fundamental change should be made to the methodology that is employed?

A: I recommend discontinuing the RPC form of decoupling, where customer growth and the associated revenues are ignored. Instead, any future decoupling for PSE sales should be a "complete" form of decoupling, where all causes of sales fluctuations are tracked in deferred revenue accounts and the Company is assured of recovering only the amounts of electric and gas revenues that were explicitly approved by the Commission.

Q: Are you aware of another regulatory commission that has adopted complete revenue decoupling in the form you recommend?

A: Yes. The Hawaii Public Utilities Commission ("HPUC") has adopted a complete decoupling regime for the Hawaiian Electric Company, Maui Electric Company, and Hawaii Electric Light Company that employs a deferral accounting mechanism referred to in Hawaii as the Revenue Balancing Account. Each of these three utilities records deferred revenues each month based upon the difference between HPUC-approved target revenues and the utility's actual recorded base revenues. The accumulated Revenue Balancing Account balances are then reconciled for recovery through the Revenue Balancing Account rate, with annual rate changes made effective June 1 of each year to recover or return cumulative variances. I have included a copy of the currently effective Hawaiian Electric Company Revenue Balancing Account tariff within Exhibit MLB-4 to illustrate how this mechanism is defined and applied. Notably, the Hawaii complete decoupling approach is part of an ongoing rate plan that includes prescribed triennial traditional general rate cases, as well as a Rate Adjustment Mechanism that calculates interim annual adjustments to target revenues based upon escalation and updating of certain costs, all limited to not exceed the percentage change in GDPPI.

Q: Why did the Washington Commission not require "found margin" from PSE customer growth to be included in PSE's existing decoupling mechanism?

A: Order 07 reflects the Commission's concern that customer growth may be too uncertain and that PSE's cost per customer may continue to increase and outstrip increased revenue from new customers:

> Our record on the question of found margin is spare and based on speculation concerning what the future may hold. We recognize that there is some potential for PSE to capture found margin from new customers that will more than offset the cost of serving those customers. However, it seems equally plausible that PSE's cost per customer will continue to increase and outstrip increased revenue from new customers. Mr. Higgins's analyses supporting the first result depend on assumptions regarding customer growth and unvarying usage per customer that are unsupported by any actual data. Mr. Piliaris's analyses and conclusions supporting the second result are based on historic trends that may or may not continue into the future. Given the uncertain future, the Commission will wish to monitor carefully the actual results of customer growth in terms of earnings over the next several years and rely on the protection of

> the earnings test, as modified by this Order, that will keep any excess earnings that may be attributable in part to customer growth from becoming a windfall for PSE. For the present, we determine that the potential that there will be found margin due to customer growth is too uncertain to establish a basis for rejecting or conditioning the decoupling mechanisms.[31]

It should be apparent from my testimony and Figure 5, above, that new revenue from customer growth is persistent and reliable, it has occurred for many historical years and expected to continue well into the future according to PSE's forecasts.

Q: Should PSE be allowed to keep customer growth revenues for shareholders, while decoupling captures all other revenue changes for recovery from customers, because of any incremental costs the utility incurs to serve new customers?

A: No. Any incremental costs to serve a new customer are quite small in relation to the margin revenues collected from that customer. The identifiable direct costs incurred to serve new customers include rate base treatment (return and depreciation) for a new meter, service line, and some modest amount of distribution network extension investment, along with monthly meter reading, billing, and remittance processing expenses, which are not offset by developer advances or contributions.

Notably, most electric and gas utility costs are relatively "fixed" costs that do <u>not</u> vary with customer counts. Indeed, a frequently cited basis for decoupling is the need to stabilize revenues to ensure collection of the utility's fixed costs. A review of PSE's electric and gas cost of service allocation studies reveals that only limited categories, which are most proximate to the customer's premise, are classified as customer-related

[31] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 (*Consolidated*), Order 07 Final Order Granting Petition, ¶ 116 (Jun. 25, 2013).

and allocated based upon customer counts.[32]

Q: What portion of PSE's overall electric revenue requirement is classified as customer-related, where the costs are viewed as caused by customer counts and allocated on that basis?

A: The portion of PSE's asserted electric revenue requirement that is classified as functionally related to serving customers is less than eight percent of the total revenue requirement.[33] This means that more than 92 percent of all revenues from new electric customers are reasonably attributed to the recovery of PSE's costs caused by demand levels or energy sales volumes, rather than costs that are incurred to connect and serve customers.

Q: Should PSE be allowed to keep customer growth revenues because of any claimed or proven attrition problem?

A: No. In response to Public Counsel Data Request No. 61(b), the Company stated, "PSE is not proposing an attrition or K-factor adjustment in this filing and objects to providing data or analyses related to mechanisms that are not included in its filing such as an attrition adjustment or K-factor. Similarly, in response to Public Counsel Data Request 283(c), the Company stated, "PSE has not proposed an attrition adjustment or requested a forecasted test year." These responses are included within my Exhibit MLB-5.

The Company has not provided any justification for retaining customer growth revenues or the "found margins" from new customers within any continuation of decoupling. It would be poor public policy to allow PSE to continue to employ RPC

[32] *See*, Piliaris, Exh. JAP-1T, at 26-34 (regarding electric cost of service classifications and at 37-52 regarding gas cost of service classifications).

decoupling, keeping the found margins from serving new customers for the sole benefit of shareholders, simply in case the Company experiences earnings attrition in the future that has not been either claimed or proven in PSE's evidence.

Q: Should the Commission continue an RPC form of decoupling for the benefit of PSE and then rely on the protection of the earnings test to return part of any excess earnings that may be attributable in part to customer growth from becoming a windfall for PSE, as suggested in Order 07?

A: No. PSE has offered no proof of any financial need for the assured revenue growth the continued RPC decoupling would provide for shareholders. The earnings sharing that has occurred during the term of the expiring rate plan provides evidence that total revenues exceeded total costs in the recent past. Moreover, customer growth revenues under RPC decoupling clearly contributed to such shared earnings. Unfortunately, customers are returned only half of any excessive revenues collected under RPC decoupling, which is later shared as excess earnings between customers and shareholders.

Q: Would continuation of decoupling in a "complete" form, rather than continuing the Company's existing RPC form of decoupling, help to simplify the administrative complexity of the decoupling mechanism?

A: Yes. For example, in rate cases, it would no longer be necessary to segregate and subtract the Basic/Minimum Charge revenues from total authorized revenue for each rate group and then divide the remaining volume-driven authorized revenue levels by the number of customers in each rate group to determine the annual allowed delivery revenue

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[33] Piliaris, Exh. JAP-7, at 6 (System Total "Customer" classified functional revenue requirement of $159,969,846 is 7.8 percent of Total Revenue Requirement of $2,055,780,445).

per customer.[34] It would also no longer be necessary to continuously track changes in the number of customers being served, in order to factor-up the authorized revenues after each rate case test year for customer growth. Instead, under complete decoupling, the Commission-authorized revenue levels for each rate group are fixed in dollar amounts for each month in a rate case and the monthly reconciliation calculations simply compare actual base revenues to the comparable authorized revenue dollar amounts, deferring the difference for later surcharge recovery or return to customers. Schedule 142 (electric) and Supplemental Schedule 142 (gas) could be simplified by deleting references to "Allowed Delivery Revenue Per Customer" from Section four and substituting references to monthly "Allowed Revenue" dollar amounts from the Commission's Order.[35] Public Counsel commits to participate with Commission Staff in the review of compliance tariff filings submitted by PSE to implement these changes.

B. Fixed Power Costs Should Be Completely Decoupled – Not Recovered Using RPC Decoupling.

Q: In discussing decoupling changes proposed by PSE, Mr. Piliaris indicates that the "PCA Settlement" requires that "if PSE's electric decoupling mechanism continues after its review in this general rate case that the mechanism would include the recovery of fixed power costs in addition to delivery costs."[36] What did the PCA Settlement say about the future treatment of Fixed Production Costs?

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[34] *See*, Jon A. Piliaris, Exh. JAP-30 (where the calculations required under RPC decoupling are presented, based upon the Company's proposed cost of service results for the electric case. Piliaris, Exh. JAP-31 contains the comparable calculations required to define inputs to the existing RPC form of gas decoupling revenue by revenue group).

[35] *See*, Piliaris, Exh. JAP-16, at 69-77 and Piliaris, Exh. JAP-25, at 36-40. Conforming changes to the unit rates used to calculate actual monthly revenues, inclusive of Basic/Minimum Charges, may also be desirable to further simplify tariff administration.

[36] Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T, at 127.

A: The Settlement Agreement in Docket UE-130583 (consolidated) described the background of regulation of PSE's power costs and then segregated such costs into two categories, "Variable Production Costs" and "Fixed Production Costs" with specific definitions of expenses by FERC account to be included in each category. The "Variable Production Costs" will continue to be tracked in the PCA imbalance calculation, while the "Fixed Production Costs" category is to no longer be tracked in the PCA imbalance calculations. Instead, regulation of this fixed category of costs was specified in paragraph six as follows:

> The Settling Parties are not bound to any position with respect to the continuation of decoupling or the treatment of Fixed Production Costs within the decoupling mechanism in PSE's next general rate case. However, if the electric decoupling mechanism continues for PSE after the review of decoupling in PSE's next general rate case, the electric decoupling mechanism will include Fixed Production Costs that were formerly tracked in the PCA mechanism and which are identified in item II B above. Nothing in this Settlement binds any party to any position with regard to treatment of costs in an automatic escalation factor mechanism (such as a K-factor) or in a multi-year rate plan.[37]

I understand that the PCA Settlement was approved by the Commission in Order 11 in Dockets UE-130617 *et al* on August 7, 2015.

Q: What is the financial impact of adding the recovery of fixed power costs into the electric revenues that are subject to decoupling?

A: The inclusion of fixed power costs within the electric decoupling mechanism would nearly double the scope and financial impact of decoupling. Exhibit JAP-30 at two shows the separate development of PSE's proposed "Annual Allowed Delivery Revenue Per Customer" and "Annual Allowed Fixed Power Cost Per Customer" under this

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[37] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-130617 et al., Settlement Stipulation, ¶ 6. (Mar. 27, 2015).

proposed expansion of decoupling. For Schedule 7 Residential Customers, the proposed annual revenues per customer subject to decoupling for recovery of Delivery Revenue is $343.74 per year. Adding Fixed Power Costs contributes an additional $316.91, resulting in the total per customer amount subject to decoupling deferral accounting and reconciliation increases to $660.65. Not only would Residential Customers be subject to large increases in the revenue dollars subject to decoupling, other non-residential electric decoupling rate groups would also experience large increases, as shown in Exhibit JAP-30.

Q: Would nearly doubling the scope of electric decoupling, through the addition of Fixed Production Costs into the revenues subject to decoupling, greatly amplify the "found margin" problem you have described that is driven by PSE's continuing customer growth?

A: Yes. The RPC form of decoupling, if also applied to Fixed Power Costs, would create nearly twice as much future revenue growth for the sole benefit of shareholders between rate cases as new customers are added to PSE's electric system. This is a completely illogical outcome, given the nature of Fixed Power Costs that have little to do with the number of electric customers being served by PSE.

Q: Do PSE's Fixed Power Costs vary with the number of customers being served?

A: No. Power supply costs are incurred to meet overall system demand and energy requirements, irrespective of the number of customers being served. At 128 of his testimony, Mr. Piliaris notes that any fixed production costs that are deferred, pending recovery through the decoupling mechanism, would be allocated among decoupling groups based upon relative contributions to the "peak credit" allocation methodology, rather than on any customer-based allocation factor. There is no basis to assume that adding new customers to the PSE system will increase the utility's fixed power costs, particularly if usage per customer is declining due to conservation effects.

Q: If Fixed Power Costs must now be added into decoupling pursuant to the PCA Settlement, does it become even more essential that PSE's decoupling mechanism be reformed into a complete decoupling mechanism like the Hawaii RBA mechanism?

A: Yes. It would be unreasonable to apply RPC decoupling to Fixed Power Cost recoveries. Doing so grants future revenue increases for this incremental block of additional cost recovery based upon PSE's expected future electric customer growth, where there has been no showing by the Company, of any actual need for a growing revenue stream to recover these costs.

Additionally, the nature of Fixed Power Costs, that are not increased when new customers are connected, also serves to argue against creating a growing revenue stream for recovery of such costs based upon PSE's growing customer count. PSE incurs Fixed Power Costs to acquire, operate, and maintain generating resources to meet peak demands and to provide energy, rather than to connect and serve new customers. This is why Mr. Piliaris uses the "peak credit" methodology to classify production costs into demand and energy components in his cost of service study.[38] Notably, no Fixed Power Costs are classified or allocated on a customer basis in PSE's cost of service study.

Q: If the Commission does not agree with your recommendation to convert PSE's current decoupling mechanism for Delivery Costs into a complete decoupling mechanism, could the newly included Fixed Production Costs (required under the

PCA Settlement) be limited to complete decoupling?

A: Yes. This could be done either by ratably updating the Customer Count data used to determine Annual Allowed Fixed Power Cost Revenue Per Customer in Exhibit JAP-30 with actual higher future customer counts. Under either approach, only the Commission-approved level of these fixed costs would be recovered prospectively, or by modifying only the Fixed Power Cost pages of Schedule 142 to replace "Monthly Allowed Fixed Power Cost Revenue Per Customer" with fixed monthly "Allowed Revenue" dollar amounts from the Commission's Order.[39]

However, a more simply administered approach would be to adopt "complete" decoupling for PSE prospectively, so that only the approved overall revenue levels across all of the base revenue requirement, including Delivery costs and Fixed Power Costs are collected in the future. This complete decoupling approach would eliminate the locked-in revenue growth problem created by the RPC approach and not leave ratepayers dependent upon future earnings sharing return only half of any excess revenues they provide to the utility.

C. Rate Test Decoupling Modifications Proposed by PSE.

Q: Mr. Piliaris references the Rate Test element of PSE's existing decoupling mechanism as intended to "ensure that customers will not experience more than a three percent increase in rates each year as a result of the decoupling mechanism," explaining that this protection operates as a "soft cap".[40] Has the Rate Test been triggered under PSE's past decoupling calculations?

[38] Piliaris, Exh. JAP-1T, at 26.
[39] Piliaris, Exh. JAP-16, at 74-76.
[40] Piliaris, Exh. JAP-1T, at 109, n.38.

A: Yes. The Gil Peach Report contains a Review of Deferral Balances and Impact of the Three Percent Cap that shows in Table VII.1 that there have been three instances where deferral balances exceeded the three percent cap and were not fully amortized.[41]

Q: Has PSE recommended any change to the Rate Test?

A: Yes. Mr. Piliaris first cites to Generally Accepted Accounting Principles that require revenue to be recovered within 24 months of the time they are accrued to be recognized as current year revenues, and an instance in 2015 when $10 million of revenue limited by the soft cap could not be recognized in PSE's reported earnings.[42] He then notes that gas residential customers have experienced very high levels of unamortized deferred revenues and setting a rate trigger higher than three percent would accelerate cost recovery.[43] On this point, the Gil Peach Report states:

> We suggest the potential problem of growing deferral balances could be addressed by raising the Rate Test from 3 percent to 5 percent for the residential natural gas decoupling group (only). In this study, the 3 percent cap has worked well for the electric decoupling groups and for the non-residential natural gas decoupling group and should be continued.[44]

With respect to the electric decoupling Rate Test, Mr. Piliaris agrees with the Gil Peach Report noting "there has not been a significant historic problem with significant unamortized deferred revenues for customers within PSE's electric decoupling mechanism." However, with knowledge of expected future expansion of the scope of decoupling, Mr. Piliaris explains that:

> the addition of fixed power cost recovery to this mechanism may create the potential for future problems…adding fixed power costs to the electric decoupling mechanism will almost double the allowed revenue recovered

[41] Piliaris, Exh. JAP-29, at 118.
[42] Piliaris, Exh. JAP-1T, at 116.
[43] *Id*., at 135.
[44] Piliaris, Exh. JAP-29, at 15.

> through the electric mechanism. This means that any variations in electric customer use will have almost double the impact on potential rate impacts in the future.[45]

He advises, "rather than wait until there is a problem, PSE proposes that the Commission heed the example experienced for gas residential customers and consider a more liberal cap to help ameliorate similar concerns for electric customers in the future."[46]

Q: What do you recommend with respect to the decoupling Rate Test?

A: I recommend retaining the existing Rate Test constraints. The primary beneficiaries of decoupling to date have been PSE shareholders, as recognized by the Gil Peach Report summaries of Schedule 142 surcharges totaling $136 million in cumulative additional electric revenues and $50 million in cumulative additional gas revenues over three years.[47] It is a modest comfort for ratepayers to have some meaningful limit placed upon annual bill impacts and the three percent level achieves that comfort. The better remedy to control the buildup of large revenue deferrals is the termination of RPC decoupling in favor of adopting complete decoupling recommended herein, where an offset in deferred revenues for customer growth would serve to limit the potential for deferrals so large they could not be recovered within 24 months. Because the costs being recovered under the mechanism are fixed costs that do not increase with increased numbers of customers, this modification is justified. Additionally, expiration of the K-factor increases that flowed through prior year decoupling calculations will further reduce the upward pressure on deferral balances.

Q: If the Rate Test is not liberalized, as recommended by PSE, does the Company

[45] Piliaris, Exh. JAP-1T at 136:1-3; JAP-1T at 136:3-8.
[46] Piliaris, Exh. JAP-1T at 136:17-19.
[47] Piliaris, Exh. JAP-29, at 47 and 48, Tables III.3 and III.7.

suffer any permanent loss of revenues when the soft cap is encountered?

A: No. If accounting rules delay the recognition of deferred revenues, that same revenue will be includable in earnings in a later reporting period with carrying charges. Thus, the financial reporting problem identified by PSE is simply one of timing, rather than any permanent loss of utility revenues or profits.

Q: Mr. Piliaris also recommends an administrative change to the input data and calculations used to perform the Rate Test.[48] Do you agree with this change?

A: Yes. It appears reasonable to calculate the inputs for the Rate Test using billing determinant data and current rate levels, as proposed by Mr. Piliaris, in the interest of efficiency. To prove the reliability of the proposed new procedure, the Company could submit the next installment of Rate Test calculations using the existing and newly-proposed procedures in side-by-side form for review by Staff and any other interested parties, to be sure no unintended variation in results is created.

D. Earnings Test Modifications Proposed by PSE

Q: Mr. Doyle criticizes the use of normalizing adjustments in the existing decoupling Earnings Test.[49] What is the purpose of the "normalizing adjustments" that he references?

A: Normalizing adjustments are used in ratemaking and in administering the PSE Earnings Test so that fluctuations in weather, power costs, and other large and potentially variable drivers of earnings do not disproportionately influence results. This causes shareholders, rather than ratepayers, to absorb normal variability in the administration of the Earnings Test in the same way they absorb such variability when base rates are established in rate cases. For example, the sales impact of unusually severe or mild weather, relative to average, and more "normal" conditions, is removed from recorded results in rate case test years and in calculation of earnings within the Commission Basis Reports ("CBRs") that are used for earnings sharing. Because the revenue requirement is determined using normalization accounting methods, the Earnings Test must be similarly normalized to produce comparable results.

Q: Why did the Commission include an Earnings Test when it approved the PSE rate plan and decoupling in its Order 07?

A: The Commission noted that, "one of the purposes of a multi-year rate plan is to provide incentives to the Company to cut costs, and allowing the potential to earn in excess of its authorized rate of return creates just such an incentive."[50] The Commission also stated, "We hope, and frankly expect, PSE to earn its authorized rate of return and do so by instituting effective cost-cutting measures. In the long run, those savings will be captured in the Company's authorized revenue requirement and savings passed onto ratepayers."[51]

Q: Should PSE's decoupling mechanism retain an Earnings Test in its present form, even though PSE has not proposed a new multi-year rate plan?

A: Yes. Decoupling is a form of single-issue ratemaking that, if continued, creates a risk of excess earnings between rate case test years. The presently authorized RPC form of decoupling greatly amplifies this risk, by granting PSE automatic revenue increases whenever new customers are added.

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[48] Piliaris, Exh. JAP-1T, at 134.

[49] Doyle, Exh. DAD-1T, at 16.

[50] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 (*Consolidated*), Order 07 Final Order Granting Petition, ¶ 161 (Jun. 25, 2013).

[51] *Id.*, ¶ 163.

The Company's other proposals also support retaining the earnings test. For example, the Company has proposed another layer of new single-issue ratemaking and revenue increases via the Electric Reliability Plan and associated Electric Cost Recovery Mechanism ("ECRM") that are addressed later in my testimony. PSE also seeks to further change the regulatory framework by formalizing an ERF procedure that would allow earnings declines to be rapidly translated into future rate increases, which advantages shareholders. There would be no comparable procedure to quickly reduce rates when and if future earnings unexpectedly increase. All of these asymmetrical changes in regulation tend to benefit the Company and its investors, and in turn support the retention of an Earnings Test for the protection of ratepayers' interests.

Q: Mr. Doyle recommends removing all "normalizing" adjustments when calculating PSE's earnings when applying the Earnings Test mechanism.[52] How would such a change impact PSE ratepayers?

A: Removing normalizing adjustments from the Earnings Test would expose ratepayers to additional risks they do not currently bear, while likely destabilizing the Earnings Test. Any earnings volatility arising from future weather fluctuations or unusual power market conditions would translate directly into more variability in PSE's earnings that, in the absence of normalizing adjustments, would impact sharable earnings amounts. For example, whenever more severe temperatures cause utility sales to be above "normal" levels, PSE would be more likely to experience higher earnings for sharing with ratepayers, while mild weather conditions would have the opposite effect.

None of this new variability in earnings caused by weather reflects management control over expenses. The more volatile future revised sharing results would be less consistent with the Commission's stated purpose of sharing, as a mechanism incent management cost-control performance. Additionally, transferring more of the earnings variability risk arising from weather and power supply conditions to ratepayers should imply a lower required ROE because of mitigated operating risks assumed by PSE investors, but no corresponding ROE reduction is recommended by Mr. Doyle if his proposed Earnings Test changes are accepted by the Commission.

Q: Mr. Doyle describes the Earnings Test as containing, "another anomaly that creates an asymmetrical earnings profile" because, "[c]urrently, the customer shares in any over-earning that PSE experiences, but does not share in any under-earning that PSE experiences."[53] Is this a valid criticism of the Earnings Test?

A: No. Ratepayers have no control over the Company's cost management efforts and should not be made to "share" any under-earnings by paying higher rates if costs are not effectively controlled by utility management. Utility management also has the ability to seek and receive rate relief whenever a showing can be made that changes in costs justify higher rates and revenues. At the time of a rate case, ratepayers become entirely dependent upon regulators to accurately evaluate the utility's financial conditions and determine new rates that are just and reasonable. However, utility management has a significant information advantage over the regulator in this process in terms of when to file for rate relief and how to structure the requested relief to optimize future earnings opportunities.

Moreover, PSE seeks to retain and expand the RPC form of decoupling that is

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[52] Doyle, Exh. DAD-1T, at 16-21.

highly favorable to shareholders and is seeking additional future single-issue rate increases for electric reliability cost recovery via ECRM, as well as formalized ERF procedures. The Earnings Test is properly asymmetrical in light of these realities. It will continue to serve as a crude but effective backstop when regulation is not able to accurately foresee and quickly react to changing future conditions that may cause PSE's earnings to grow above authorized levels.

Q: Mr. Doyle asserts that the "asymmetrical earnings profile, biased to the downside" tends to increase PSE's risk profile in a way that should be "taken into consideration when setting PSE's ROE." Alternatively, he argues that "a more direct way to address the problem is to re-introduce the 25 basis point dead band into the sharing mechanism as originally proposed by PSE and NWEC."[54] Do you agree?

A: No. The Earnings Test has no effect whenever normalized earnings do not exceed authorized ROE levels and serves only to limit the Company's earnings upside above that level whenever revenues grow more quickly than costs. I defer to the witnesses addressing cost of capital in this proceeding as to any risks to be assigned to the elements of the regulatory framework that may impact authorized levels of ROE for the Company. However, once the ROE has been established, there is no reason to arbitrarily "undo" that finding to liberalize the 50/50 sharing already found reasonable by the Commission, by adding a 25 basis point dead band above that finding. To do so would weaken the consumer protection provided by the earnings test in the first instance.

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[53] Doyle, Exh. DAD-1T, at 21.
[54] *Id*., at 25.

E. Commercial Rate Group Modifications Proposed by PSE.

Q: Mr. Piliaris discusses some historical changes to the non-residential rate groupings used within PSE's decoupling mechanism and then recommends some opportunities to rearrange and improve such rate groupings.[55] Have you reviewed these proposed changes?

A: No. I have not analyzed this issue. I am aware that in Order 07, the Commission observed that, "there undoubtedly is significant heterogeneity in the non-residential customer class" but then determined not to exclude non- residential customers from the decoupling mechanisms. Order 07 left the door open for reconsideration of how decoupling is applied to non-residential customer classes, stating:

> The Commission determines that we should not at this time exclude from the decoupling mechanisms non-residential customers other than electric lighting and retail wheeling customers, and gas lighting, gas water heater rentals and special contracts. However, we strongly encourage customers such as Kroger and Nucor Steel, and trade organizations such as ICNU and NWIGU, to engage in meaningful dialogue with PSE, Staff and others who take an interest, and with the Commission, to monitor carefully how decoupling is working out in practice. It may be that there are alternatives for some, or all, non-residential customers that are better suited to meeting decoupling's goals than are the current decoupling mechanisms. The Commission remains open to hearing fully supported alternative proposals for fixed cost recovery from the non-residential class of customers, or subsets of the class.[56]

I understand that Public Counsel may comment further upon this issue later in this proceeding.

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[55] Piliaris, Exh. JAP-1T, at 111-113 and 117-120.

[56] *Wash. Utils & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 (*Consolidated*), Order 07 Final Order Granting Petition, ¶ 129 (Jun. 25, 2013).

V. ELECTRIC RELIABILITY PLAN / COST RECOVERY MECHANISM

Q: What does PSE propose regarding its so-called Electric Reliability Plan?

A: Ms. Gilbertson describes gas and electric system infrastructure, operations, and service quality performance and issues in her testimony. She describes additional "steps" that "can be taken to further improve service reliability."[57] Ms. Gilbertson describes PSE's "worst performing circuits" and problems with cable failures caused by certain high molecular weight ("HMW") cable that was installed prior to 1982 and proposes that a "model similar to the Gas CRM would be beneficial in enhancing PSE's electric reliability [by] allowing PSE to recover prudently incurred costs related to the repair, improvement and replacement of specific, targeted aging infrastructure through an electric cost recovery mechanism."[58] Specifically, "PSE proposes an Electric Cost Recovery Mechanism focus on (i) accelerated replacement of underground distribution HMW cable, and (ii) aggressively addressing the worst performing circuits." [59]

Ms. Koch dedicates her testimony to more detailed definition of what she calls "PSE's request for an Electric Reliability Plan and associated Cost Recovery Mechanism"[60] stating:

> PSE proposes a framework that is very similar to the framework set forth by the Commission in the natural gas Accelerated Replacement Policy. PSE believes that the robust workshops and input gained through the development of the Accelerated Replacement Policy provide a strong foundation that can be similarly applied to the Electric Reliability Plan and associated Cost Recovery Mechanism.[61]

The proposed Plan consists of two parts: (1) a Master Plan to address all the proposed

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[57] Gilbertson, Exh. BKG-1T, at 30- 37.
[58] *Id.*, at 32, ll. 3-6.
[59] *Id.*, at 30-32.
[60] Direct Testimony of Catherine A. Koch, Exh. CAK-1CT, at 1, ll. 15-16.

assets; and (2) a Two-Year Plan that specifically identified the program goals for the next two calendar years with the Two-Year Plan presented in Ms. Koch's 44-page Exhibit CAK-3C.[62]

A third PSE witness, Ms. Barnard, sponsors certain accounting and revenue requirement definitions, proposes filing procedures for the Electric Cost Recovery Mechanism ("ECRM"), and sponsors Exhibit KJB-9 to illustrate workpapers for a revenue requirement model that is proposed to derive the ECRM charges to customers.[63]

Q: Has PSE quantified the amount of extra revenue requirement it is initially requesting through its newly proposed ECRM?

A: Yes. Annual revenue requirements for the estimated Two-Year Plan spending would continue for seven years, starting at $10.5 million in year one and gradually declining to about $8.0 million by year seven. Mr. Piliaris, in Exhibit JAP-32, allocates the $10.5 million of the first year ECRM revenue requirement among customer classes. He also sponsors a new Schedule 149 tariff captioned Electric Reliability Cost Recovery Mechanism ("ERCRM") at 78 of his Exhibit JAP-16, populated with the unit rates calculated on Exhibit JAP-32.

Q: Should the Electric Reliability Plan proposed by PSE be considered and approved by the Commission?

A: No. The Commission should decline to accept responsibility for the analysis and prioritization of PSE's electric infrastructure investment decisions that are properly the domain and responsibility of utility management. PSE management has detailed access

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[61] *Id*., at 9, ll. 5-9.
[62] *Id.*, at 10, ll. 7-13.
[63] Barnard, Exh. KJB-1T, at 73-83.

to operational information about its distribution system and possesses the human and financial resources to best manage the utility. It is doubtful that the Commission or its Staff possesses the detailed analytic tools and PSE's electric distribution system performance data to independently evaluate the Company's reliability investment optimization plans. Indeed, the Company does not expect the Commission or its Staff to replicate network modeling or analysis that has already been done by PSE and is merely looking for the Commission and interested parties to:

> provide input on whether the Plan is measured and reasonable from the Commission's perspective. PSE would expect a response regarding any concerns with the Plan to occur in a timely fashion. If through the review process the Plan is determined to not be reasonable and measured, PSE would return to historical spending levels."[64]

PSE presents its view of the role of the Commission and its staff, as well as other background information regarding the proposed ECRM, in greater detail in PSE's responses to Public Counsel Data Request Nos. 48, 51, and 73 which are included in my Exhibit MLB-6.

Q: If more electric reliability investment is truly needed, does continued traditional regulation provide sufficient incentives to optimize such spending?

A: Yes. PSE can expect that its prudent new investment in reliability improving plant in service would be includable in rate base and would earn a return for many future years. Additional spending on vegetation management and depreciation on new reliability investment is also generally recoverable through rates. There is no significant financial disincentive to make prudent investments in the Company's electric transmission and distribution system. Moreover, new system reliability investments are made every year,

[64] Exh. MLB-6, PSE Response to Public Counsel Data Request No. 73(d).

based upon management's informed discretion regarding need and affordability, as shown in Figure 3 of Ms. Gilbertson's Direct Testimony.[65]

Fundamentally, the question around adequacy of reliability investment is binary. Either planned spending levels for electric reliability investments are adequate or they are not. If more spending is justified in the near term, it should occur without regard to PSE's ability to charge ratepayers more for such spending through an ECRM. If planned spending without the ECRM is already optimal, it would be inefficient and wasteful to encourage increased spending through Commission intervention and approval of the Electric Reliability Plan. PSE should declare whether its proposed Electric Reliability Plan is appropriate or not and then spend accordingly, without demanding extra pay for somewhat better service.

Q: Should the Commission approve the ECRM surcharges and the new Schedule 149 tariff, through which PSE seeks piecemeal recovery of more expansive reliability investments after approval of the Electric Reliability Plan?

A: No. For many reasons, the ECRM proposal represents poor regulatory policy and has not been supported by any evidence of financial need for additional revenues from ratepayers. The ECRM and Schedule 149 should be rejected because:

- PSE has not demonstrated any financial inability to finance and make all needed electric reliability investments, without separately charging customers for recovery of such costs.
- PSE has not justified piecemeal ratemaking for Electric Reliability Plan

[65] Gilbertson, Exh. BKG-1T, at 26-17.

investments, by showing that cost reductions elsewhere in the business, new revenues from RPC decoupling (if continued) or expense savings enabled by Electric Reliability Plan investments are not available to offset or help "pay for" such investments.

- The costs arising from the Electric Reliability Plan are not large or volatile in amount and are not beyond the control of utility management. Therefore, extraordinary ratemaking for such costs in inappropriate.
- PSE's reliance upon the gas CRM as precedent for an electric CRM is misplaced, because the gas CRM was designed for the narrow purpose of accelerating the replacement of potentially dangerous pipeline facilities to reduce the risk of failure in the interest of public safety.[66]
- Adoption of an electric CRM for PSE would create an additional layer of regulatory filings and review proceedings, for which potentially significant costs could be imposed upon the Commission and its staff, as well as concerned interveners, particularly if CRM-like mechanisms are proposed by other investor-owned Washington utilities seeking to maximize returns for their shareholders.

I recommend adherence to the more broadly applied regulatory approach to electric reliability investments, where the Commission monitors service level and reliability metrics and provides guidance with respect to actual performance in relation to established guidelines and comparisons to peer utilities.

[66] *Wash. Utils & Transp. Comm'n Related to Replacing Pipeline Facilities with an Elevated Risk of Failure*, Docket UG-120715, Commission Policy on Accelerated Replacement of Pipeline Facilities With Elevated Risk, at 10-11 (Dec. 31, 2012).

Q: Is a filed reliability improvement "plan" or a rate surcharge mechanism needed for a utility regulatory agency to effectively oversee and encourage utility service quality?

A: No. It is not unusual for service quality issues to be presented in utility rate cases where performance can be evaluated in the context of allowed ROE or in the design of specific service quality incentives or penalties. This focus upon results, rather than in prescribing spending programs and funding levels, properly recognizes that the expertise and information to support more granular analysis of service issues and the making of electric reliability investment funding optimization decisions resides within the utility and its management, not at the Commission.

Q: Is there evidence that PSE is financially able to fund all needed electric reliability investments?

A: Yes. First, the Company's actual electric and gas Capital Expenditures incurred over the past six years have ranged from a high of $535 million in 2012 to a low of $357 million most recently in 2016.[67] Thus, in the past four years, PSE has reduced its capital spending by approximately one third, or $178 million. This reduction amount is a significant multiple of the incremental spending PSE proposes to accelerate under its Electric Reliability Plan, only if ECRM funding from ratepayers is provided, suggesting that there is ample financial capacity within PSE to increase reliability spending toward historical levels.

The Puget Energy Consolidated business characterizes itself as having a "Strong liquidity position, manageable debt profile and access to capital" with access to more than $1.5 billion of liquidity as of December 31, 2016, in its April 2017 Bondholder Presentation.[68]

Q: In your previous answer, you referenced the Company's declining capital expenditure ("CAPEX") levels since 2012. Are further declines in planned T&D capital investment planned by PSE?

A: Yes. According to the same Bondholder presentation referenced above, T&D Operational CAPEX spending is predicted to decline to $271 million in 2017, $253 million in 2018 and $257 million in 2019. These projections imply an ability for PSE to fund the planned incremental reliability investments by simply slowing the rate of planned reductions in T&D CAPEX, rather than demanding higher rates through an ECRM. I have included a copy of this presentation within Exhibit MLB-7, excluding the Appendix pages for brevity.

Q: Has PSE failed to prudently invest in needed electric utility reliability investments in prior years in the absence of an Electric CRM?

A: No, it appears this is not the case. According to the Company's response, it has "prudently invested in reliability investments as discussed in the Prefiled Direct Testimony of Booga K. Gilbertson" and has "recovered prudent investments through normal general rate case proceedings".[69]

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[67] Gilbertson, Exh. BKG-3, at 1.
[68] *See*, Puget Energy, *Puget Energy and Puget Sound Energy 2016 Year End Update*, at 36 (April 2017) http://www.pugetenergy.com/past_events_pdfs/2017_April_Bondholder_Presentation.pdf.
[69] PSE Response to Public Counsel Data Request No. 7.

Q: Does PSE contend that the costs of its proposed 2017 and 2018 Electric Reliability Plan is only prudently incurred <u>if</u> the Commission approves the Electric CRM cost recovery proposal?

A: No. The company stated, "PSE's proposed plan specifically targets improvements that are prudent irrespective of the Commission's approval of the ECRM. PSE will complete these projects per the historic spending level and timeframe if the ECRM is not approved."[70]

Q: Does PSE contend that the costs of its proposed 2017 and 2018 Electric Reliability Plan are affordable to the Company only if the Commission approves the Electric CRM cost recovery proposal?

A: No. When PSE was asked this question in Public Counsel Data Request No. 72 the Company responded only indirectly, saying PSE's proposed plan "is an increased annual expenditure which is beyond historic spending levels" and "accelerating this type of investment" was characterized as "challenging consideration the approximate 27 months or more of regulatory lag associated with traditional ratemaking." Please see Exhibit MLB-8 for copies of PSE responses to Public Counsel Data Request Nos. 71, 72, and 75 addressing the Electric Reliability Plan and ECRM proposal.

Q: Why have you characterized the Company's ECRM proposal as piecemeal ratemaking and poor regulatory policy?

A: The ECRM proposes to charge ratepayers separately for a single element of the Company's revenue requirement that is associated with discrete new investments in reliability enhancing facilities. Piecemeal or single-issue ratemaking should generally be avoided because it violates the matching principle of ratemaking by ignoring other changes in future revenues and costs that could offset the selected element of increasing cost. For example, if the Commission continues to allow an RPC form of decoupling, over the objections stated herein, PSE will realize steadily growing future revenues with no showing of financial need for such increased revenues. It is quite possible that such RPC-driven revenue growth, when coupled with other changes in the utility's costs of service, may be more than adequate to fund increased electric reliability investments.

The Electric Reliability Plan itself should create operational savings if it is effectively deployed, by reducing the Company's expenses to respond to outage calls and to maintain older and deteriorated equipment. However, the Company's calculation of proposed ECRM charges does not account for such savings.[71]

Q: Are the costs arising from the Company's proposed Electric Reliability Plan so large and volatile in amount that extraordinary rate treatment is appropriate?

A: No. The revenue requirement arising from these investments is neither particularly large nor volatile from year to year.

Q: Are the costs arising from the Company's proposed Electric Reliability Plan beyond the reasonable control of management, such that they merit special regulatory treatment?

A: No. In fact, the proposed surcharges through the ECRM appear to be aimed at inducing management to spend more on reliability projects than the Company's existing management controls (that are driven primarily by PSE's financial goals) would justify.

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[70] Exh. MLB-8, PSE Response to Public Counsel Data Request No. 72.

[71] See Barnard, Exh. KJB-9, where no negative O&M expense element is included for estimated cost savings.

Q: Should the Company's proposed ECRM be approved because it is patterned after the Gas Cost Recovery Mechanism?

A: No. I understand that the Commission authorized the Gas Cost Recovery Mechanism after conducting an extensive investigation into measures needed to enhance the safety of natural gas systems in Docket UG-120715. In that Docket, the Commission held workshops, received testimony, and reviewed Pipeline Replacement Plans from several utilities, including PSE. In that Docket, the Commission found it in the public interest for all gas companies to take a proactive approach to replacing pipe that presents an elevated risk of failure.[72] No similar investigatory proceeding or public interest finding justifies approving an extraordinary rate recovery mechanism for targeted electric reliability investments that are now proposed for special funding via PSE's new ECRM.

Q: Has PSE described or quantified the administrative burden that would result from installation of a new Electric Reliability Plan review process and then administration of a new surcharge tariff to separately recover the costs of any approved plan?

A: Not that I have seen within the Company's evidence. If PSE and other Washington electric utilities submitted an Electric Reliability Plan comparable to Exhibit CAK-3C with all of the periodic filings described by Ms. Barnard[73], the review effort and expense imposed upon Commission Staff (and any concerned intervenors) would be significant. In the event any dispute arose over the reasonableness of specific proposed projects or around the definitions used to isolate costs eligible for special ECRM recovery from

[72] *Wash. Utils & Transp. Comm'n Related to Replacing Pipeline Facilities with an Elevated Risk of Failure*, Docket UG-120715, Commission Policy on Accelerated Replacement of Pipeline Facilities With Elevated Risk, ¶ 37 (Dec. 31, 2012).

other project costs incurred in the normal course of business, considerable additional resources could be consumed in litigating such disputes.

VI. FORMALIZATION OF EXPEDITED RATE FILING ("ERF") PROCEDURES

Q: What has PSE proposed with respect to a desire for "Expedited" future rate filings?

A: According to PSE witness Barnard:

> [t]he purpose of an ERF is to update the base rates established in PSE's general rate case with known and measurable changes since the test year. In PSE's 2011 general rate case, Commission Staff proposed an expedited filing methodology that would allow PSE to update the 'relationships between rate base, revenues, and expenses' in its rates on an expedited basis in order to address some of the regulatory lag inherent in Washington's historical ratemaking approach."[74]

However, Ms. Barnard notes that when the Commission approved PSE's expedited rate filing in 2013 the Commission indicated that it was a one-time mechanism, such that there is now "uncertainty" as to whether the Commission would consider a newly filed ERF on an expedited basis.[75] Ms. Barnard describes PSE's view of how an ERF process should be formalized in the future, to remove such uncertainty, suggesting the following procedures:

- Utilization of Commission Basis Reports ("CBR") data as inputs to "update" PSE's costs with no pro forma adjustments.
- Completion of an ERF within 60-90 days of filing
- Exclusion of Power Costs and Purchased Gas Costs
- No updated of the Cost of Capital
- No restriction or limitation upon PSE's ability to request an attrition adjustment or

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[73] Barnard, Exh. KJB-IT, at 77-79.
[74] Barnard, Exh. KJB-1T, at 68.
[75] *Id*., at 69.

multi-year rate plan, even if ERF procedures are formalized.

Mr. Piliaris has retained PSE's Schedule 141 Expedited Rate Filing Adjustment within Exhibit JAP-16 at pages 55-68 and Exhibit JAP-25 at pages 30-34 at zero rate levels, presumably to serve as the vehicle for rapid implementation of any future rate increases requested pursuant to a formalized ERF.

Q: Has PSE committed to file an ERF whenever its future earnings, as reported in its CBR reports, <u>exceed</u> the return levels approved in the Company's most recent general rate case?

A: No. Instead, the Company appears to anticipate continuation of earnings sharing, where ratepayers could receive only 50 percent of shareable excess earnings, instead of a base rate reduction within 60-90 days based upon updated rate case inputs under the ERF process. As noted earlier, even with earnings sharing continued, Mr. Doyle complains that such earnings sharing is asymmetrical and warrants a higher authorized ROE or a dead-band before sharing begins. If an ERF process is formalized for use by PSE upon request, it would be reasonable to make the same vehicle symmetrically available to the Commission Staff or intervenors to effect for expedited rate reductions. Notably, PSE has not identified a mechanism through which the Commission Staff or another party could initiate a permanent rate reduction through ERF that would be effective in 60-90 days in place of 50 percent sharing of excess earnings, so as to symmetrically apply ERF procedures.

Q: If an ERF approach is formalized, should there be any time limitation placed on the interval after a general rate case order is issued and within which an ERF could be requested?

A: Yes. I believe than any ERF application should be limited to a period of 12 months after the issuance of a final order in a general rate case. Even with this filing date interval limitation imposed, the financial data being updated could be up to two years old.

Consider the test year ending September 30, 2016, in the pending rate case. It will include data back to October of 2015, which will be about two years old, when the order is issued in this proceeding. If an ERF was filed in late 2018, within 12 months of the order in the pending rate cases, it could employ updated data through September of 2018, a full two years of "fresher" data than was last used to set rates.

Q: What does PSE propose with respect to ERF procedure limitations and time intervals?

A: PSE would allow an ERF filing up to two years after the date rates became effective in the prior general rate case.[76] Such a liberalized schedule is excessive, since an updating of input data spanning up to three years beyond the last formal test year exposes ratepayers to changes in the cost of capital or the need for new and different ratemaking adjustments than were considered in the previous rate case.

Q: Does the risk of new issues or major changes in the utility's operations argue against using ERF procedures, where there is no opportunity for new ratemaking adjustments or for detailed regulatory scrutiny of changes?

A: Yes. The formalized ERF proposed by PSE would employ Commission Basis Reports ("CBR") data as inputs, using prescribed adjustments from prior rate cases to "update" PSE's costs with no new pro forma adjustments.

Q: Are there examples of new and different adjustments that have been proposed by

PSE in developing its asserted revenue requirement in the pending rate cases, where no comparable adjustments were included in the prior rate case?

A: Yes. In each of the Company's 2009, 2011, and 2017 general rate cases, there were several new and different ratemaking adjustments proposed by PSE that were not reflected in the prior rate case. For example, in the current case, Ms. Barnard's adjustments KJB-6.19 through KJB-6.21 and KJB-7.07 through KJB-7.12 (within Exhibits KJB-6 at 19-21 and KJB-7 at 8-13, respectively) are all new or unique to the pending rate filing and were not included in the Company's 2011 general rate case filing. Similarly, in comparing the prior 2011 rate case to the 2009 case, many new and unique ratemaking adjustments were proposed, even though the cases occurred within two years of each other. Please see Exhibit MLB-9 for the Company's description of the changes in ratemaking adjustments.

The obvious need for new or revised ratemaking adjustments from one rate case to the next within PSE's filed evidence illustrates a very basic problem with the ERF process, which re-applies only the same adjustments that were last approved by the Commission in determination an updated revenue requirement. Facts and conditions change and new ratemaking adjustments are routinely required to address such changes. Reliance upon CBR reports to drive expedited rate adjustments under a formalized ERF would leave no room for the development and consideration of new adjustments that may become appropriate in the period since the last general rate case.

When consideration is given to the opportunity for Commission Staff or intervenor witnesses to develop and present adjustments independently, in areas where

[76] Exh. MLB-10, PSE Response to Public Counsel Data Request No. 393.

PSE has proposed no adjustment, an expedited ERF review proceeding cannot provide the needed public interest protections that more formal discovery procedures and review intervals in a general rate case tend to provide. These facts argue for limiting ERF applications to 12 months after a general rate case order is issued and expanding the timeframe to process an ERF case beyond the 60 to 90 days proposed by PSE.

Q: According to Ms. Barnard, one of the most critical elements is for ERF rates to be implemented in a condensed period, such as a 60 to 90 day timeframe.[77] Is this an adequate amount of time for Staff and other concerned parties to mobilize resources, analyze the filing, conduct any needed discovery, and confirm that the asserted ERF request is reasonable?

A: No. This proposal assumes that Staff and intervenor parties are standing by with available and uncommitted resources to immediately respond to any ERF filing and assumes the need for very limited discovery or a single "round" of questions is needed. PSE has assumed that all parties to the last general rate case will be familiar with PSE's books and records, without regard to problems some parties may have in retaining on short notice the same consultants they may have relied upon for services in the prior rate case. Short notice may pose a problem in retaining consultants generally, given that litigation schedules fill up several months in advance.

A larger problem is the inability for Staff and other parties to independently analyze the Company's books within only a few weeks of time, in order to identify any unusual or non-recurring transactions, or to understand other new facts and circumstances that need to be addressed with different regulatory adjustments or remedies. PSE would retain only for itself the flexibility to apply ERF procedures, using only previously approved adjustments and rate of return findings, or instead file a general rate case with the attendant flexibility to propose different adjustments and an updated rate of return when the latter approach is more favorable to the utility.

Q: Is PSE willing to implement ERF rates subject to refund if its filing is protested by the Staff or another party, so that adjudicative proceedings can occur?

A: Yes. But in the Company's view this would only occur if the Commission determines that an adjudicative proceeding is necessary. PSE then believes such an adjudicative proceeding should be able to be completed within the 120-day period after suspension. These views are stated in the Company's response attained through discovery, which is included in Exhibit MLB-10.

Q: Is it problematic for an ERF filing to hold constant the cost of capital last found reasonable by the Commission for up to two years after a rate order?

A: Yes. Changes in capital market conditions can become large with the passage of time. Allowing more than one year after a general rate order for the filing of an ERF increases the likelihood that cost of capital findings in that rate order have become unreasonably stale. Any ERF proceeding should update the cost of debt capital, because this is a fairly mechanical calculation that tends to be non-controversial. However, there is likely no expedited method to update the cost of equity that would be readily accepted by the parties to an ERF.

Q: Does the same staleness concern exist with respect to changes in load conditions and changes in the allocation of costs between customer classes?

[77] Barnard, Exh. KJB-1T, at 69.

A: Yes. Absent a limitation of 12 months for an ERF filing after a general rate order, there is an increased risk that the cost of service allocations and rate design analyses performed in the prior rate case are less indicative of cost causation and appropriate rate designs. With this in mind, any ERF filings made within 12 months of a general rate order should distribute revenue increases ratably among customer classes and rate elements, to avoid raising potentially complex and controversial rate design issues that are frequently encountered in general rate cases.

Q: Has PSE justified its request for formalization of ERF procedures with the parameters described in its testimony?

A: No. PSE has not shown that there is any need for formalized ERF procedures containing the parameters they propose. Without claiming or proving any attrition problem at this time, PSE leaves open the possibility of presenting an attrition adjustment in the future and is not willing to accept a general rate case moratorium in exchange for formalized ERF procedures. Notably, PSE has provided (1) no evidence it will face any future earnings attrition, (2) has offered no general rate case moratorium in return for a formalized ERF, (3) seeks to continue the RPC form of decoupling with automatic, customer-driven revenue increases, and (4) has proposed piecemeal ECRM rate increases, even if ERF procedures are formalized. All of these proposals shift the regulatory framework to benefit utility shareholders, placing ratepayers at a disadvantage with little benefit in return. Considering all of the Company's proposed changes to the Washington regulatory framework, PSE ratepayers would be exposed to piecemeal ECRM rate increases, continued RPC decoupling revenue increases, unrestricted future expedited ERF rate increases along with unrestricted traditional rate cases, in whatever combination produces the best financial results for the utility.

Q: What is your recommendation with respect to PSE's requested formalization of ERF procedures?

A: I do not recommend any formalization of ERF procedures at this time because PSE has not proven that it will face any significant earnings attrition problem prospectively. In the absence of any financial need for abbreviated and expedited rate relief, the Commission should not formalize ERF or otherwise liberalize ERF procedures in ways that may disadvantage ratepayers, as more fully described herein. Schedule 141 should be deleted from the Company's electric and gas tariff.

Q: In the event PSE actually suffers real and significant future earnings attrition, is other relief available to the Company?

A: Yes. The Company retains the ability to file a general rate case at any time. Additionally, I understand that interim rate relief is available in Washington under extraordinary circumstances.

Q: Does this conclude your testimony at this time?

A: Yes.