

**EXH. CAK-4T
DOCKETS UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: CATHERINE A. KOCH**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

**Docket UE-170033
Docket UG-170034**

**PREFILED REBUTTAL TESTIMONY
(NONCONFIDENTIAL) OF
CATHERINE A. KOCH
ON BEHALF OF PUGET SOUND ENERGY**

AUGUST 9, 2017

PUGET SOUND ENERGY

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1 **PUGET SOUND ENERGY**

2 **PREFILED REBUTTAL TESTIMONY**
3 **(NONCONFIDENTIAL) OF**
4 **CATHERINE A. KOCH**

5 **I. INTRODUCTION**

6 **Q. Are you the same Catherine A. Koch who submitted prefiled direct testimony**
7 **on January 13, 2017, on behalf of Puget Sound Energy (“PSE” or the**
8 **“Company”) in this proceeding?**

9 A. Yes.

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

11 A. My rebuttal testimony provides response to several intervenors regarding four
12 topics: the Electric Reliability Plan (“ERP”) and Electric Cost Recovery
13 Mechanism (“ECRM”), the 24-hour and 120-hour Service Guarantee, Institute of
14 Electrical and Electronics Engineers (“IEEE”) Standard-1366 application in storm
15 deferral, and the Ardmore Substation. The ERP and ECRM received response
16 from Thomas Schooley on behalf of Staff of the Washington Utilities and
17 Transportation Commission (“Staff”), Michael Brosch and Barbara Alexander on
18 behalf of Public Counsel, Michael Gorman on behalf of the Industrial Customers
19 of Northwest Utilities (“ICNU”), and Kevin Higgins on behalf of Kroger. My
20 testimony addresses concerns these intervenors have regarding 1) the need for a
21 mechanism, 2) the relevance to the Gas Cost Recovery Mechanism (“CRM”), and
22 3) the need to focus on reliability.

1 Barbara Alexander on behalf of Public Counsel raised concerns regarding the process and
2 awareness of the 24-hour and 120-hour service guarantee. Thomas Schooley on behalf of
3 Staff raised concerns regarding the use of the IEEE Standard-1366 for triggering storm
4 deferral accounting. Finally, the Ardmore Substation project received response from
5 Bradley Mullins on behalf of ICNU.

6 **II. ELECTRIC RELIABILITY PLAN AND ELECTRIC COST**
7 **RECOVERY MECHANISM**

8 **Q. Why has PSE proposed the ERP and the ECRM?**

9 A. PSE is proposing the ERP and ECRM to address immediately two important
10 issues that affect the reliability and resiliency of service to customers: 1) failure
11 prone high molecular weight (“HMW”) direct bury cable and 2) infrastructure
12 failures or limitations on PSE’s worst performing circuits (“WPC”). By
13 addressing these two issues, PSE will significantly improve the reliability and
14 resiliency of service to customers beyond historic levels.

15 As explained in my prefiled direct testimony, the cause of PSE’s cable failure is
16 generic to all HMW cables due to inferior technology and is not based on
17 manufacturer or location. Thus, the HMW cable is currently failing throughout
18 PSE’s service territory. Therefore, the only way PSE can protect customers from
19 outages caused by failing HMW cable is by proactively and aggressively
20 accelerating replacement of this cable before it fails. Additionally, while historical
21 planning processes facilitate investments that support achievement of overall
22 reliability service quality levels, these processes tend to concentrate reliability

1 investments to more densely populated areas. Customers served on the WPC tend
2 to be in lower density areas. While some investments are made in these WPC
3 areas, additional specific focus will be needed to improve reliability beyond
4 historic levels.

5 In effect, the ERP and associated ECRM is a holistic compliment to existing
6 reliability planning methodology in that it provides for more reliability
7 investments to serve customers in all parts of the service area and addresses a
8 known outage-prone population of underground cable.

9 **Q. Why is PSE proposing a separate cost recovery mechanism instead of**
10 **traditional ratemaking to recover the costs for the ERP?**

11 A. The Prefiled Rebuttal Testimony of Daniel A. Doyle, Exhibit DAD-7T, addresses
12 the benefits of the proposed ECRM over traditional ratemaking. If PSE relies on
13 traditional ratemaking to implement the ERP, the Company will face ongoing
14 earnings erosion due to the regulatory lag associated with traditional ratemaking.
15 As described in the Prefiled Rebuttal Testimony of Katherine J. Barnard,
16 Exhibit KJB-17T, the financial impact associated with implementation of just the
17 2017 investment, absent the ECRM, will be approximately \$20 million based on
18 the 27-month regulatory lag associated with a general rate case (“GRC”) filing.

1 **Q. Are there other reasons why PSE should not implement this work under the**
2 **traditional rate making model?**

3 A. Yes. In a recent Avista GRC, the Commission expressed a general expectation
4 that utilities would not increase capital investment in non-revenue generating
5 distribution plant beyond customer growth rates.¹ The level of spending PSE is
6 proposing in the ECRM to accelerate key reliability spending exceeds the revenue
7 generated from customer growth. Thus, PSE is unwilling, through traditional
8 ratemaking, to engage in the accelerated level of electric reliability spending that
9 PSE has proposed in its ERP. PSE seeks Commission authorization of the
10 acceleration of this reliability work through approval of the ECRM, rather than
11 engaging in a level of work that may be second-guessed under the traditional rate
12 making model. In short, PSE will be unable to implement the target improvements
13 proposed in the ERP at the proposed accelerated timeframe if the ECRM is not
14 approved.

15 **Q. What other benefits does the ECRM provide?**

16 A. In addition to rate recovery, through the ECRM, PSE and the Commission can
17 review the progress, objectives, and expenditures of the ERP on an annual basis
18 instead of waiting until the next GRC. It allows both PSE and the Commission to
19 be in agreement regarding PSE's reliability activities. Additionally, it benefits

¹ See *WUTC v. Avista*, Docket Nos. UE-150204/UG-150205, Order 05 at ¶ 116 (Jan. 6, 2016).

1 customers because it provides for a more predictable, smaller annual rate impact,
2 as opposed to a larger lump sum impact at the next GRC.

3 **Q. Doesn't the ECRM constitute single-issue ratemaking and provide improper**
4 **“piecemeal revenue increases”?**

5 A. It is true that the ECRM is focused on electric reliability in primarily two specific
6 areas. This mechanism creates a narrow focus of funds that can only be used to
7 address HMW cable and the WPC and as such, provides greater transparency and
8 accountability to addressing these issues. The Prefiled Rebuttal Testimony of
9 Daniel A. Doyle, Exhibit DAD-7T, describes the evolution of ratemaking and the
10 fact that over the past several decades, commissions across the United States have
11 approved various forms of riders, tracking mechanisms, and other innovative cost
12 recovery mechanisms to supplement their respective GRC processes when
13 traditional ratemaking is less efficient. These alternative mechanisms have
14 become increasingly common in recent years. Indeed, this Commission has
15 approved a variety of different alternative mechanisms, including the Gas CRM.
16 Viewed in this context, the establishment of the ECRM, which serves an
17 important purpose of accelerating spending for reliability in two critical areas, is
18 not a departure from today's ratemaking practices.

1 **Q. ICNU witness Mr. Gorman claims that costs recovered in a rider, such as the**
2 **ECRM, are only appropriate when the costs are significant, volatile, and**
3 **beyond a utility's control. What is your response?**

4 A. The Commission has not consistently followed the guidelines Mr. Gorman
5 suggests. As explained in the Prefiled Rebuttal Testimony of Daniel A. Doyle,
6 Exhibit DAD-7T, the expenditures planned in the ECRM are significant, and
7 volatility is not always a factor in determining whether it is appropriate or not to
8 establish a tracking mechanism. Moreover, in addition to being significant, the
9 costs proposed to be recovered through the ECRM are, in many ways, beyond
10 PSE's control. This is especially true regarding the HMW cable, which is rapidly
11 failing. While PSE has been investing in replacing this cable for decades, due to
12 other reliability demands on PSE system, replacement is simply not occurring
13 soon enough. As I explained in my prefiled direct testimony, to adequately
14 address the failing cable, it will cost approximately \$600 million. This cannot be
15 addressed on an accelerated basis through PSE's traditional reliability efforts.

16 For PSE to substantially improve reliability, it will require a departure from the
17 traditional approach of only replacing infrastructure after failure. Waiting until
18 additional HMW cable fails or additional outages occur in WPC areas before
19 replacement provides a disservice to customers. However, addressing these issues
20 before failure occurs requires funding beyond PSE's typical ongoing distribution
21 system maintenance and modernization expenditures. This is further explained in
22 the Prefiled Rebuttal Testimony of Katherine J. Barnard, Exhibit KJB-17T.

1 **Q. Is the infrastructure associated with the ECRM also accounted for in the**
2 **Expedited Rate Filing (“ERF”)?**

3 A. No. The Response Testimony of Michael Gorman, Exhibit MPG-1T, on behalf of
4 ICNU, incorrectly concluded that the infrastructure accounted for in the ECRM
5 was also accounted for in the ERF. The ECRM would be an annual filing that
6 trues-up costs. The benefit of a separate mechanism, as opposed to including it in
7 the ERF, is that the ECRM not only addresses the recovery of the reliability
8 investments, but it creates transparency to the work PSE is doing to improve
9 reliability and the specific benefits it brings. Furthermore, inclusion in the ERF
10 does not fully address the regulatory lag or PSE’s concerns of spending beyond
11 what is supported by growth. Please see the Prefiled Rebuttal Testimony of
12 Katherine J. Barnard, Exhibit KJB-17T.

13 **Q. In proposing the ECRM, is PSE requesting pre-approval into rates of**
14 **infrastructure that is not known and measurable similar to traditional**
15 **ratemaking processes?**

16 A. No. PSE is not asking for pre-approval or for investments to be put into rates prior
17 to being known and measurable. Like the Gas CRM,² which per the
18 Commission’s policy statement requires Commission approval of the plan, the
19 ECRM would not put into rates investments that are not known and measurable

² “Gas CRM” includes the Gas Pipeline Replacement Plan and the Gas Cost Recovery Mechanism.

1 nor would it eliminate the prudence test prior to doing so. The ECRM proposal
2 requests the same process as the Gas CRM for Commission approval of the
3 annual plan. The plan approval by the Commission ensures agreement that
4 accelerating reliability spending above historic levels is a reasonable and
5 measured approach to improving reliability for customers and ensures
6 engagement through the process. This step will support the more timely prudence
7 review at the end of the year when the work is complete.

8 **Q. Does the proposed ECRM shift risk from PSE to customers?**

9 A. No. Mr. Gorman asserts that cost recovery via the ECRM would shift risk from
10 PSE to customers. This is incorrect. PSE will still be responsible for
11 demonstrating prudence prior to the ECRM investment being put into rates. No
12 cost recovery risk is shifted to customers. As described in the Prefiled Direct
13 Testimony of Katherine J. Barnard, Exh. KJB-1T, page 77, only actual costs of
14 completed projects are requested to be put into rates at the conclusion of the
15 year's work.

16 **Q. Will the ECRM require more Staff review than the traditional ratemaking**
17 **process?**

18 A. I do not believe so. Mr. Schooley and Mr. Brosch assert that the ECRM process
19 would be burdensome for Staff to oversee and would require significant review
20 effort and expense. However, neither has yet to provide evidence that definitively
21 supports these assertions. From PSE's experience with the Gas CRM, PSE does

1 not believe that the ECRM will require more review than the traditional
2 ratemaking process. While the first year of the Gas CRM took more time for all
3 involved, each subsequent year has resulted in a review process that generates
4 fewer questions from Staff due to the familiarity with the process and the quality
5 of information provided by PSE. Like a GRC, Staff can and has asked PSE
6 questions throughout a given plan year to ensure their comfort with the prudence
7 and progress. And any time spent by Staff on the proposed ECRM would be
8 offset by time saved during a GRC. For example, in the current GRC, Staff has
9 not submitted any data requests to PSE regarding the Gas CRM nor have issues
10 regarding the Gas CRM been raised, which indicates that their time spent
11 reviewing the Gas CRM during the year has minimized Staff's time during the
12 GRC.

13 Moreover, Staff already has expressed interest in engaging in electric reliability
14 and planning discussions as highlighted by activities such as the econometric
15 reliability benchmark study per WUTC Docket U-151958 and the Integrated
16 Resource Planning ("IRP") rulemaking per WUTC Docket U-161024. Staff's
17 engagement in the ECRM would complement and further benefit these additional
18 activities.

19 **Q. Do you address whether Kroger's proposal to recover ECRM cost through**
20 **demand charges for demand billed schedules is appropriate?**

21 A. No. The Prefiled Rebuttal Testimony of Jon A. Piliaris, Exhibit JAP-46CT
22 addresses this issue in response to Mr. Higgins' concern.

1 **Q. Why would the ECRM incent a consistent work plan?**

2 A. PSE must balance many priorities that serve customer and stakeholder interests
3 from year to year. The ability to recover investments in a timely manner following
4 the installation year removes uncertainty associated with the traditional
5 ratemaking process. The removal of the uncertainty allows PSE to commit to a
6 consistent investment plan that is more than one year out. By not needing to alter
7 the plan each year, PSE can more effectively coordinate with other projects in the
8 public interest, such as public improvement and transportation projects and is able
9 retain resources more readily. For example, as my prefiled direct testimony
10 indicated, the ERP proposes to accelerate the replacement of the failure prone
11 HMW cable from 25-30 years to 10 years. This is a significant increase in the
12 number of projects annually as compared to historical levels, which requires more
13 resources to accomplish successfully. The ECRM would provide PSE with the
14 ability to implement a more consistent work plan for the replacement of HMW
15 cable and address WPCs.

16 **Q. Ms. Alexander testifies that the ECRM should be rejected because the State**
17 **of Washington has not authorized such a rider by legislation. How do you**
18 **respond?**

19 A. The Commission does not need legislation to approve the ECRM. Indeed, the
20 issuance of the Accelerated Pipeline Replacement Policy by the Commission did
21 not require legislation, but rather was a collaborative effort between Washington
22 utilities and the Commission to prioritize replacement of higher risk pipelines.

1 The impetus of the pipeline safety conversation was the San Bruno, California
2 incident. PSE does not subscribe to a philosophy that unfortunate events are
3 needed to drive a collaborative conversation and process that focuses on
4 reliability which is of core interest to PSE, the Commission, and customers. It is
5 undisputed that having a reliable distribution system is of critical importance to
6 our customers and communities. Accordingly, PSE believes the increasing trend
7 of outages is an impetus to engage in a transparent process to improve reliability
8 while recognizing the need to eliminate the regulatory lag that discourages
9 spending above customer revenue.

10 **Q. How is the reference to the Gas CRM appropriate?**

11 A. The testimonies of Mr. Schooley, Mr. Brosch and Ms. Alexander suggest that
12 comparison or use of the Gas CRM as precedent for the ECRM is inappropriate.
13 The fact that the Gas CRM does not specifically address electric infrastructure
14 does not mean the comparison is not useful. The reference to the Gas CRM is
15 helpful for several reasons. The Gas CRM demonstrates that a process similar to
16 what is proposed in the ECRM has already been successful in Washington,
17 including successful engagement with Staff, transparency to the plan and benefits,
18 and monitoring of progress for known and measurable results prior to putting in
19 rates the following year. The ECRM mechanism would leverage the extensive
20 roadmap established by the Gas CRM process, but does not need to be reinvented
21 through lengthy proceedings.

1 **Q. What similarities does the Gas CRM have to the ECRM proposal?**

2 A. There is similarity in that both the Gas CRM and the ECRM are addressing
3 infrastructure that is failing and impacting customers and the public. The Gas
4 CRM proactively addresses “higher risk pipelines” that have potential to fail, not
5 unsafe or dangerous pipelines as incorrectly implied by the response testimonies.
6 PSE addresses dangerous or unsafe pipelines immediately, and they are not part
7 of the Gas CRM process. The Gas CRM allows for the proactive replacement of
8 failing pipelines to prevent the occurrence of leaks and their impact. Similarly, the
9 ECRM proactively addresses HMW direct bury cable that are failing to prevent
10 outages and subsequent impact. Doing this ensures the electric system is reliable
11 and minimizes safety and other concerns resulting from outages such as street
12 lights, traffic signals, climate control, security systems, and other frustrations
13 associated with power outages.

14 **Q. Does PSE agree it is obligated to provide reliable service and see it as an**
15 **important objective?**

16 A. Yes. PSE takes the obligation of providing reliable service seriously. As discussed
17 in the Prefiled Direct Testimony of Booga K. Gilbertson, Exhibit BKG-1T, PSE
18 has been making effective reliability investments; however, PSE has seen an
19 upward trend in both tree related and underground cable outages despite these
20 investments. The transparency of the proposed ECRM provides an opportunity to
21 improve reliability beyond historic levels for tree related and cable related power
22 outages, but it comes with added cost. By virtue of the ECRM, PSE can address

1 WPCs more aggressively and proactively prevent outages from impacting service
2 by failure-prone HMW direct bury cable. Approval of the ECRM would
3 demonstrate the Commission's agreement that accelerating reliability spending
4 beyond historical levels is a reasonable and measured approach to improve
5 reliability for customers.

6 **Q. How do you respond to Ms. Alexander's assertion that the elimination of the**
7 **SQI No. 3 SAIDI penalties and historical change in the benchmark indicates**
8 **PSE sees reliability as unimportant?**

9 A. PSE disagrees with Ms. Alexander's assertion. Indeed, the opposite is true. The
10 removal of penalties and redesign of SQI No. 3 was part of a negotiated
11 settlement approved by the Commission that also implemented a new 24-hour
12 service guarantee. The service guarantee connects PSE's actions directly to
13 customers that suffer lengthy outages by paying those customers rather than
14 paying a penalty that does not directly benefit customers. Ms. Alexander fails to
15 mention that there was an agreement to address and reevaluate the SQI No. 3
16 benchmark following implementation of the Outage Management System
17 ("OMS").

18 **Q. Have any of the interveners objected to PSE investing in reliability?**

19 A. No intervenors objected to PSE investing in reliability. In fact, Mr. Brosch agrees
20 that PSE has prudently invested in needed reliability investments. The concerns
21 expressed by the parties focus primarily on the regulatory mechanism suggested

1 through the ECRM and the methodology for reviewing the investments proposed
2 and completed.

3 **Q. Has PSE demonstrated the need for such investments, and the benefit to its**
4 **customers of its increased level of capital investments?**

5 A. Yes. PSE acknowledges and has demonstrated that it has been generally below
6 the performance of its peers in reliability due in large part to the challenges that
7 come with heavily treed terrain, and that there is a trend upwards for tree and
8 vegetation caused outages and equipment failure, which is unacceptable.³ Indeed,
9 Staff's recent preliminary conclusions from their econometric study would
10 suggest PSE's reliability performance should be better than it is,⁴ which supports
11 more investment in these areas where reliability has been challenging. PSE has
12 provided a detailed plan that addresses prioritization of work, the specific projects
13 and areas of focus. PSE has also demonstrated the overall benefits to its customers
14 of its increased level of capital investment. The ERP and ECRM will aid PSE in
15 addressing the reliability for customers who live in less populated and more treed
16 areas and customers that are served by HMW direct bury cable in a more
17 proactive manner.

³ Prefiled Direct Testimony of Booga K. Gilbertson, Exh. BKG-1CT at 29.

⁴ PSE does not fully agree that the data analysis developed by Staff reflects grid operation in the Northwest as of yet, but PSE is willing to continue working together to develop an analysis model that can be supported. That said, refined analysis would likely still result in a gap between targets presented and PSE's actual performance.

1 **Q. How does PSE know customers want better reliability and this is in the**
2 **public interest?**

3 A. In addition to the importance to our communities, business, schools and hospitals
4 that a reliable and resilient power grid provides, PSE hears from customers
5 throughout the year how important reliability is to them and the negative impact
6 that power outages cause them personally. For example, one customer on a worst
7 performing circuit submitted a complaint which was submitted to PSE, as follows:

8 The customer said the electric system that serves his community has a high
9 number of outages and needs to be replaced or buried underground . . . the
10 customer would like the Co. to look at the history over 10 years to see that their
11 community has too many outages. Customer feels the Co. is spending more
12 money on band-aids and repairs than they would to just upgrade the service.
13 Customer is frustrated at the number of outages and wants a permanent fix.⁵

14 In analyzing the JD Power Electric Residential survey results as of April 2017, the
15 largest factor that separates PSE from the utility with the highest satisfaction
16 rating is power quality and reliability, which is about 28% of customers' overall
17 satisfaction with their utility. Additionally, the J.D. Power study shows that when
18 customers perceive that a rate increase is being driven by investments in
19 infrastructure, reliability, and power supply, price satisfaction increases. Finally,
20 in 2015, the Lawrence Berkley National Laboratory ("LBNL"), the leader in

⁵ WUTC Customer Complaint 110951 (Mar. 11, 2011).

1 developing the framework and analysis for estimating the value of service for
2 electric utility customers in the United States, released its Updated Value of
3 Service Reliability for Electric Utility Customers in the United States report,
4 which provides insight into the growing value that electric customers place on
5 reliable power due to the costs they incur as a result of outages.⁶ This can be for
6 an array of reasons, such as loss of productivity for those who work at home, or
7 the inability to efficiently use household devices or appliances requiring power.
8 For example, according to LBNL, in 2014, the estimated cost for a customer
9 interruption has increased 54% since 2009.⁷ Considering customer rates along
10 with the economic impact of lower than desired reliability is important. The
11 existence of reliability metrics, nationwide surveys to measure customer
12 perceptions of reliability such as JD Power Surveys, and the already established
13 objectives set by Resilient Washington and the Presidential Quadrennial Energy
14 Review, affirms that reliability and resiliency is in the public interest.

15 **Q. Does PSE have a specific benefit or target improvements in reliability the**
16 **ERP will achieve?**

17 A. Yes. As discussed in my prefiled direct testimony, ERP investments in 2017 and
18 2018 are expected to eliminate 167,000 customer interruptions and 14.08

⁶ Exh. CAK-5.

⁷ *Id.* at 38.

1 customer minutes.⁸ Investments in 2017 and 2018 will benefit customers in over
2 75 communities served by PSE. The ERP will prioritize projects and continue to
3 focus on the respective circuits until there is a 50% improvement in the
4 reliability.⁹ Ms. Alexander incorrectly asserts that PSE has not established what
5 level of outages or failures is acceptable. Relative to HMW direct bury cable, the
6 ERP establishes that the acceptable target for outages on HMW is zero, as this
7 type of outage can be prevented unlike many other types of outages. Relative to
8 the WPCs, PSE's plan provides criteria for prioritizing work,¹⁰ which is the
9 threshold for what is unacceptable—the WPC circuits that have more than
10 750,000 customer minute interruptions which serve an average of 1,700
11 customers. This translates to 12 hours of non-storm power outage duration each
12 year. This is more than four times longer than the 155 minutes PSE system SAIDI
13 SQI No. 3 established in 2016. By addressing reliability more aggressively,
14 customers gain economic value associated with their ability to depend on reliable
15 power in today's technology driven culture.

⁸ Exh. CAK-3C at 8 and 14.

⁹ The 50% improvement is in the baseline measurement used to justify the project, whether it be SAIDI, SAIFI, CMI, or CEMI.

¹⁰ Exh. CAK-3C at 6 and 12.

1 **Q. Ms. Alexander testifies that alternatives such as distributed energy resources**
2 **(“DER”) should be considered. Has PSE considered these alternatives?**

3 A. Yes. PSE’s process is to select the optimal reliability solution for a given
4 application. Alternative solutions, such as DER, are in the portfolio of solutions
5 regularly considered to improve reliability.¹¹ The absence of these alternatives in
6 the plan does not mean these types of alternatives have not been considered.
7 While PSE will continue to explore DER, to date, the DER available have limited
8 application and need further maturity regarding dependability in lieu of replacing
9 infrastructure, such as replacing aging underground cable and improving
10 reliability on the WPC. DER alternatives typically still require infrastructure
11 between customers and as a result, PSE could not simply abandon circuit
12 infrastructure altogether. As PSE continues to build the foundation required for
13 utility scale DERs, including two-way communication systems, distribution
14 management systems, and robust protection and automation, these alternatives
15 will become more viable.

¹¹ Prefiled Direct Testimony of Booga K. Gilbertson, Exh. BKG-1T at 9.

1 **Q. Does PSE agree that the ECRM is unnecessary because it is a subject in the**
2 **IRP rulemaking in WUTC Docket 161024?**

3 A. No. In the workshops PSE has participated in thus far, PSE has not heard that the
4 IRP rule would consider rate recovery processes in the future. Further, work such
5 as replacing aging infrastructure is beyond the scope of the IRP.

6 **III. SERVICE GUARANTEES ARE APPROPRIATE**

7 **Q. Does PSE agree with Public Counsel witness Alexander's testimony that the**
8 **24-hour and 120-hour service guarantees need to be changed?**

9 A. No. These service guarantees were addressed in settlement discussions in 2016
10 and were the subject of a Commission order approving the settlement dated June
11 17, 2016. As discussed in more detail below, Public Counsel participated in the
12 settlement conferences that addressed these service guarantees, among other
13 things, and Public Counsel expressed approval of the service guarantees to the
14 Commission. It is surprising that Public Counsel is now raising issues about the
15 service guarantees. There is no need for the Commission to reopen these service
16 guarantees one year after approving a settlement that addressed these issues.

17 **Q. What issues does Ms. Alexander raise with respect to the service guarantees?**

18 A. Ms. Alexander asserts that customers may not be receiving due credit relative to
19 these service guarantees due to 1) lack of an automatic process that instead
20 requires customers to report their outage or specifically call to obtain the
21 guarantee; 2) the calculation of duration starts only from time the customer places

1 the call; and 3) the efforts of PSE to raise awareness have not provided clear
2 understanding of the process. Ms. Alexander provided no evidence that these
3 assertions are true and she ignores the fact that the Commission approved a
4 settlement addressing these issues only last year.

5 **Q. Please describe the creation of the 24-hour service guarantee.**

6 A. On November 30, 2015, PSE filed a proposed permanent modification of SQI No.
7 3 SAIDI mechanics in WUTC Docket UE-072300, which initiated multi-party
8 settlement discussions per Commission Order 26 on December 31, 2015. PSE,
9 Commission Staff, and Public Counsel met for a series of nine settlement
10 meetings to discuss the mechanics and benchmarks. Staff and PSE reached a
11 settlement; Public Counsel did not join in the settlement due to a disagreement
12 over whether penalties should remain for SQI-3.

13 As an outcome of that settlement, PSE and Staff agreed to nine terms including:

- 14 • the establishment of a new customer guarantee that requires PSE to: (i)
15 provide a \$50 bill credit to customers who are without power for 24 hours, or
16 more, under certain circumstances (excluding Major Events) and who have
17 either requested the guarantee or reported their outage; and (ii) inform
18 customers about the new 24-hour customer guarantee and how to take
19 advantage of the guarantee;
- 20 • retention of the customer guarantee that requires PSE to provide a \$50 bill
21 credit to customers who have been without power for 120 hours or more and

1 who have either requested the guarantee or reported the outage which includes
2 outages that occur during Major Events;

- 3 • inform customers of consecutive years missed on PSE's annual service quality
4 report card, if applicable; and
- 5 • the elimination of potential monetary penalties for missing the SAIDI
6 benchmark.
- 7 • The Commission approved this multi-party settlement on June 17, 2016. Since
8 that time, PSE has met its commitments under the terms of the settlement
9 agreement and specifically the 24-hour guarantee, and PSE continues to
10 enhance the processes.

11 **Q. Did Public Counsel object to the new 24-hour service guarantee, as designed**
12 **in the settlement?**

13 A. No. Public Counsel submitted a letter to the Commission acknowledging its
14 approval of the service guarantees, including the new 24-hour guarantee that
15 requires customers to report an outage or request the guarantee:

16 Public Counsel views positively the retention of PSE's 120-hour
17 customer guarantee and establishment of a new 24-hour customer
18 guarantee under Tariff 131. The new 24-hour customer guarantee
19 would apply during non-major events only. Under the new 24-hour
20 guarantee, customers who report an outage lasting 24 hours or
21 longer, and customers who request the 24-hour guarantee, will
22 receive \$50. This guarantee, and the 120-hour guarantee, provides

1 customers with some compensation for the harm and
2 inconvenience of being without power.¹²

3 **Q. Why does PSE encourage customers to report their outage?**

4 A. Customer reporting of outages continues to be an important factor for PSE in
5 identifying and restoring outages. Since the implementation of the OMS in 2013,
6 PSE is able to automatically identify reporting customers' locations on an
7 electronic network map when the customer calls in, and from that, OMS is able to
8 predict the source of the outage so that response personnel can be dispatched
9 promptly to the source of the outage. OMS can receive information about an
10 outage either via SCADA communications that identifies a possible outage at the
11 system level such as a substation or by customer reporting. Customer reporting
12 outage locations provide for the best prediction model and ability to be confident
13 when the outage is restored. Substation level information may not result in
14 identifying all the customers due to circuit configuration variances.

15 **Q. Is the process for reporting an outage difficult?**

16 A. No. PSE has made significant improvements over that last several years in
17 providing self-service systems such as useable mobile apps for outage reporting,
18 making web pages and outage maps easier to access and making these tools
19 known to the public. For example, for the time period January through May 2017,

¹² Docket UE-72300, June 9, 2016 Letter from Lisa Gafken, for Public Counsel, p. 3; *see also* Order 29, Final Order Approving and Adopting Settlement, ¶ 31 (June 17, 2016).

1 74.21% of reported outages were through customer self-service systems including
2 the online and web/mobile services and Interactive Voice Response (“IVR”)
3 systems, which indicates how easy PSE has made it to provide the required
4 reporting. In comparison to May 2015, only 64.7% of reported outages were
5 through self-service systems.

6 **Q. Has PSE focused effort on ways to raise awareness of the service guarantees**
7 **and how to use the tools?**

8 A. Yes. PSE was required to raise customer’s awareness of the service guarantees
9 per the multi-party settlement regarding SQI No. 3, SAIDI. Attachment A of the
10 settlement described ways PSE would raise awareness, and these were approved
11 by the Commission on June 17, 2016. Exhibit CAK-6, which is PSE’s Response
12 to Public Counsel Data Request No. 025, provided examples of PSE’s efforts to
13 raise awareness, including: three news stories, a press release, five customer
14 newsletter inserts, including information on the envelope, year round pse.com
15 posted information, and the relevant IVR and access center call representative
16 scripts. PSE develops these tools with web designers and communication experts.
17 The awareness efforts are making an impact. For example, in May 2015, only
18 2.71% of outages were reported using the web/mobile tools with 61.99% reported
19 via IVR. Since raising awareness efforts implemented in 2016, in May 2017,
20 22.27% of outages were reported using the web/mobile tools with only 49.79%
21 reported via IVR.

1 **Q. Is PSE improving the overall process associated with the service guarantees?**

2 A. Yes. In December 2016, PSE introduced the OMS feature that provides proactive
3 alerts to customers when PSE is aware a customer is out of power. Customers
4 must subscribe to receive these notifications through their myPSE account profile.
5 Currently, there are about 500,000 email and 350,000 text subscriptions to PSE's
6 OMS notification system. This equates to 30-50% of PSE's electric customers.
7 When PSE does its post-event review of outages, if the outage qualifies under the
8 guarantee, this program recognizes the customer for having reported the outage if
9 they received an alert from PSE acknowledging they were out. These customers,
10 and those that report the outage, automatically receive the \$50 credit on their next
11 bill. Until PSE has all contact information and can depend on the meter data via a
12 strong AMI system, deviating from the requirement for customers to report their
13 outage is not appropriate.

14 **Q. Is it correct that the calculation of the duration of the outage starts only from**
15 **the time the customer reports the outage as Ms. Alexander claims?**

16 A. No. The duration of the outage starts when an outage is created in OMS, which
17 occurs when information is received from SCADA, AMR, or when a customer
18 reports the outage. It is true that when the customer call is the first awareness that
19 an outage has occurred, the calculation starts from that time. If the customer calls
20 or PSE proactively alerts the customer after an outage is created in OMS, the time
21 of the call or alert does not affect the calculated duration. This would have to be

1 the case since a customer can request the guarantee up to seven days after an
2 outage.

3 **IV. IEEE APPLICATION FOR STORM DEFERRAL**

4 **Q. Do you agree with Mr. Schooley’s proposal to discontinue using the IEEE**
5 **Standard 1366 for deferral of costs for major storm events?**

6 A. No. This standard was first proposed by Staff in PSE’s 2004 GRC for use in
7 determining the threshold for deferral of costs related to major storm events.¹³
8 The storm deferral methodology has been reviewed and accepted by the
9 Commission, with minor changes, in several cases and most recently in PSE’s
10 2011 GRC.¹⁴ As agreed upon, it is slightly “modified” from the IEEE Standard
11 1366 as it includes all outage events greater than one minute whereas IEEE
12 Standard 1366 defines an outage event as greater than five minutes.¹⁵ It is
13 consistent with industry research with respect to the classification of major storm
14 events and allows PSE to recover the cost of storm repairs resulting from major
15 events, once storm costs exceed the annual threshold. As discussed in the Prefilled
16 Rebuttal Testimony of Katherine J. Barnard, Exhibit KJB-17T, Mr. Schooley’s

¹³ *WUTC v. PSE*, Dockets UG-040640/UE-040641, Testimony of Douglas Kilpatrick, Exh. DEK-1T at 4-17.

¹⁴ *WUTC v. PSE*, Dockets UE-111048/UG-111049, Order 08 at ¶¶ 297-99 (May 7, 2012).

¹⁵ This difference in recorded outages between one and five minutes is negligible as they are on average ~ 0.02% of the total Customer Minute Interruptions (2011 through 2016). This is about 808,303 customer minute interruption differences with an impact an average SAIDI difference of about 0.13 minutes.

1 recommendation is contrary to past Staff testimony and recommendations on this
2 topic. I encourage the Commission to maintain the existing storm deferral
3 mechanism that relies on the modified IEEE Standard 1366 for determining when
4 storm costs may be deferred.

5 **Q. Why is it important for PSE to be allowed to defer and amortize storm costs**
6 **resulting from major storm events?**

7 A. Major storm events cause significant disruption in service and require PSE to
8 focus substantial resources on timely storm repair. Timely storm response, repair
9 and resolution of outages is very important to customers and PSE. In PSE's
10 service territory, storm events are not a theoretical concern. PSE's service
11 territory is located in the Puget Sound Convergence Zone and is subject to
12 frequently severe weather. Further, as mentioned in the Prefiled Direct Testimony
13 of Booga K. Gilbertson, Exhibit BKG-1T, almost 75 percent of PSE's right of
14 way is flanked by trees, which compounds the impact of wind events. Restoration
15 efforts result in significant costs that PSE should be allowed to recover to further
16 its goal of providing safe and reliable service to its customers. The events are
17 beyond PSE's control and create variability and volatility in rates for customers if
18 not deferred.

19 **Q. Please describe IEEE Standard 1366.**

20 A. IEEE is the leading authority in electric power technologies and advancements. It
21 has roots dating back to 1884 with more than 420,000 members in over 160

1 countries with more than 1,300 active standards and 500 in development. Through
2 its global membership, IEEE leads technical collaboration in areas ranging from
3 aerospace systems, computers and telecommunications to biomedical engineering,
4 electric power and consumer electronics. In 2004, Commission Staff witness Mr.
5 Kilpatrick provided testimony noting his support¹⁶ of the IEEE Standard 1366-
6 2003 at the time that established common definitions for indices used to measure
7 electric system reliability and introduced this concept of “major events.”¹⁷
8 Although neither IEEE Standard 1366-2003 nor IEEE Standard 1366-2012
9 specifically discuss its use in accounting mechanisms, in the 2004 GRC, Mr.
10 Kilpatrick testified in support of using this standard to determine storm deferral
11 triggers.¹⁸ IEEE Standard 1366 defines the methodology and calculation of a
12 major event day threshold value, T_{MED} , which is based on values of daily SAIDI
13 for the previous five years.

¹⁶ *WUTC v. PSE*, Dockets UG-040640/UE-040641, Testimony of Douglas Kilpatrick, Exh. DEK-1T at 4-17.

¹⁷ IEEE SA-1366 2003 and IEEE SA-1366 2012 is Guide for Electric Power Distribution Reliability Indices.

¹⁸ *WUTC v. PSE*, Dockets UG-040640/UE-040641, Testimony of Douglas Kilpatrick, Exh. DEK-1T at 4-17.

1 **Q. Does having more than 2.3 major event days per year mean PSE is**
2 **incorrectly categorizing storms or that the standard is inappropriate, as Mr.**
3 **Schooley claims?**

4 A. Mr. Schooley is correct that the 2.5 beta value should, in theory, result in, on
5 average, 2.3 major event days (“MED”) per year. However, the fact that PSE has
6 had more than 2.3 major event days should not invalidate the methodology or its
7 application. The IEEE Standard 1366-2012 methodology assumes a log-normal
8 distribution of daily SAIDI; utility outage data follows a log-normal distribution
9 approximately, but not perfectly.

10 The performances of different values of beta were examined by the IEEE
11 distribution working group which found “There is no analytical method of
12 choosing an allowed number of MEDs/year.” The IEEE distribution working
13 group members reached a consensus of 2.5 beta,¹⁹ but noted that for a “wide range
14 of distribution utilities, more than 2.3 days were usually classified as MEDs.”
15 Actual IEEE benchmarking survey results validate that statement. The IEEE
16 Benchmarking survey of the 2013 results show that the number of MEDs
17 experienced by the 93 participating utilities ranged from 0 to 11 with an average
18 of 3.53 MEDs per year with 55% of the utilities having more than 2.3 MEDs. The
19 IEEE Benchmarking survey of the 2011 results show that the number of MEDs
20 experienced by the 90 participating utilities ranged from 0 to 23 with an average

¹⁹ Beta refers to the standard deviation from the average.

1 of 6.8 MEDs per year with 76% of the utilities having more than 2.3 MEDs in
2 2011. With this in mind, the IEEE methodology remains sound and is used by the
3 majority of utilities to bring consistency and comparability of reliability indices
4 irrespective of the size or geography of utilities. It is a methodology used by all
5 the other utilities in the Washington state for the purposes of reporting SAIDI
6 performance.

7 **Q. Why is the modified IEEE Standard 1366 an appropriate standard to use for**
8 **determining when storms should be deferred?**

9 A. Mr. Schooley's suggestion that IEEE Standard 1366 creates an inaccurate
10 representation of storm patterns because not all qualifying events are
11 "catastrophic storms" is incorrect. The word "severity" or "catastrophic" is also
12 not specifically used in the IEEE Standard 1366. A MED is defined as those
13 instances that exceed the reasonable design and or operational limits of the
14 electric power system; it, in essence, separates normal events from unusual events
15 for the purposes of monitoring trends and performance. It is only recently that
16 IEEE has begun debating the term "catastrophic event" within its utility work
17 groups as a result of observing the trend of increasing T_{MED} across utilities due to
18 very extreme events. These work groups have been leaning towards defining
19 catastrophic as exceeding 4.5 beta but this has not been formally published in a
20 standard as of yet.

1 **Q. Are there other types of storm events for which PSE incurs costs?**

2 A. Yes. There are other storm events that do not meet the modified IEEE standard.
3 From 2007 to 2016, there were 33 storm events that did not meet the modified
4 IEEE standard threshold. Additionally, from 2007 to 2016, there were four days
5 that met the T_{MED} threshold but were where the extreme weather was localized.
6 Restoration costs associated with these 37 events are not included in the deferral
7 mechanism.

8 **Q. Are there costs that are related to qualifying storms that are not deferred?**

9 A. Yes. Even when associated with a qualifying event, some costs cannot be
10 deferred. Only incremental transmission and distribution electric system repair
11 costs incurred by the Company during qualifying storm event may be deferred
12 such as overtime pay for employees, outside contractor costs, and stores material
13 and material overheads to name a few. Straight-time labor costs associated with
14 professional engineers that normally do not charge time to work orders, straight-
15 time labor costs for stores personnel or fleet services personnel are all examples
16 of costs that are not deferred.

17 **Q. Do you have concerns with Mr. Schooley's proposal for PSE to seek deferred**
18 **accounting treatment for each storm rather than using the existing storm**
19 **deferral mechanism?**

20 A. Yes. It would be burdensome for PSE to take time to support the preparation of an
21 accounting petition to defer storm costs while the Company is facing a storm and

1 engaged in restoration efforts. My understanding is, without automatic deferral,
2 storm costs would not be eligible for deferral until an accounting petition is filed,
3 and any costs incurred before the filing are not eligible for deferral. It would be
4 burdensome for operations personnel to take time out to assist in the preparation
5 of an accounting petition during a storm.

6 V. ARDMORE PROJECT

7 A. Overview of Ardmore Substation

8 **Q. Please describe the Ardmore Substation for which Mr. Mullins seeks a**
9 **disallowance.**

10 A. The Ardmore Substation, located in the heart of the Bel-Red area in Bellevue,
11 Washington, functions as both a distribution substation and a transmission
12 switching station and was necessary to meet the increased demand for electricity
13 in the south Redmond/northeast Bellevue area and to improve electric reliability
14 for customers. The three 115 kV transmission lines and nine substation
15 transformers serve 39 distribution circuits and 29,000 customers in the Bel-Red
16 area. The final configuration of Ardmore Substation included the combining of
17 Interlaken and Ardmore Substations on the same site. As a result, the nearby
18 aging Interlaken Substation was decommissioned. Planning for the Ardmore
19 Substation began in 2006, and it was placed into service June 6, 2012. Final work,
20 including decommissioning the Interlaken Substation, was completed June 30,
21 2014. From 2006 to 2014, the project and associated scope progressed from
22 planning to design, permitting, and construction.

1 **Q. Does PSE agree that \$13.6 million of costs for the Ardmore Substation costs**
2 **should be disallowed as Mr. Mullins asserts in his testimony?**

3 A. No. PSE made prudent decisions and controlled costs, consistent with
4 construction and engineering best practices, throughout the lifecycle of the
5 Ardmore Substation project. From Mr. Mullin's hindsight perspective, based on
6 one document, he asserts incorrectly that the higher costs of the project are
7 attributed to assumptions about constructability issues due to the urban area,
8 PSE's purchase of materials before a final site was selected, and PSE's alleged
9 failure to address a contracting issue in a timely manner. His views are erroneous
10 as discussed in more detail below.

11 **Q. Why did PSE not discuss Ardmore specifically in the GRC testimony?**

12 A. The Ardmore substation has been in service since 2012. PSE does not attempt to
13 address each transmission and distribution expenditure or project undertaken for
14 reliability and capacity needs in its direct case. It would be burdensome for PSE
15 to provide this level of data in its direct filing for all the gas and electric
16 transmission and distribution capital expenditures that have since been put into
17 service since 2010, the test year in PSE's last GRC. For perspective, the total
18 amount of electric transmission and distribution capital work for that time period
19 is approximately 208,514 orders,²⁰ totaling approximately \$2.25 billion. In this

²⁰ A project is made up of multiple orders.

1 case, as in past cases, PSE provides detail of transmission and distribution
2 expenditures when requested through data requests.

3 **Q. Did PSE provide information regarding the Ardmore substation in response**
4 **to discovery requests?**

5 A. Yes. PSE provided abundant detail regarding Ardmore in discovery,
6 approximately 529 files related to the Ardmore Substation in response to ICNU
7 Data Request No. 040. These files contain detail that supports the Company's
8 prudence with respect to the Ardmore project which is discussed in more detail
9 below.

10 **Q. How was the allocation of Ardmore relative to Schedule 40 determined to be**
11 **appropriate?**

12 A. The reallocation of costs associated with Schedule 40 is addressed in the Prefiled
13 Rebuttal Testimony of Jon A. Piliaris, Exhibit JAP-46CT.

14 **B. The Ardmore Substation Meets the Prudence Standard**

15 **Q. Please briefly describe the need for Ardmore.**

16 A. Mr. Mullins summarizes the need for Ardmore well which was to reliably serve
17 the anticipated customer growth in southwest Redmond and northeast Bellevue.
18 Exhibit CAK-7 is a planning summary that supports the need for the project,
19 which was provided in response to ICNU Data Request Nos. 024 and 040.
20 Anticipated growth was due to expansion of a large computer software

1 developer's campus and the recent re-zoning of the Bel-Red and Overlake area to
2 higher density multi-use, commercial and multi-family use.

3 **Q. Were there existing reliability concerns that supported the need for the**
4 **Ardmore substation?**

5 A. Yes. The existing transmission line configuration no longer provided the needed
6 reliability and capacity to serve those areas. For example, by 2010, there were
7 already many days of the year when transferring customer load from either one of
8 two adjacent substations for maintenance or due to equipment failure would not
9 be possible without customer outages. Additionally, the number of substations on
10 the transmission line prevented the use of automatic switching and remote power
11 outage restoration due to the complex configuration thereby increasing power
12 outage impact even more. Additional detail is provided in PSE's Response to
13 ICNU Data Request No. 040, Exhibit BGM-8.

14 **Q. Please briefly describe the evaluation of alternatives for meeting the need.**

15 A. PSE evaluated the following alternatives for which more detail can be found as
16 discussed in Exhibit BGM-8:

- 17 1) A switching station at Kenilworth. This was eliminated as an option due to the
18 need to condemn property and greater difficulty in connecting transmission
19 lines.
- 20 2) Underground transmission was evaluated to address reliability, but this added
21 significant cost.

1 3) Accelerating the switching station at Westminster and deferring the new
2 switching station was considered. This option was eliminated due to reduced
3 reliability to Kenilworth and Lake Hills area, it did not address the impact of
4 multiple equipment failure and it increased future costs and customer impact
5 due to having to rework later when needed.

6 **Q. How did PSE keep management informed during the evaluation of the**
7 **project?**

8 A. Management was informed and engaged in key decisions consistent with the
9 phase and scope of the project. This included seven project presentations, three
10 project reports, twelve project change requests, and regular progress reports.

11 **Q. Did PSE maintain adequate documentation of this project?**

12 A. Yes. PSE's contemporaneous documentation demonstrates the need, the
13 evaluation of alternatives, the justification for the cost, and the involvement of
14 PSE management as already described. As noted above, PSE provided over 500
15 documents to the parties during discovery. Exhibit CAK-8 summarizes some of
16 the documentation of significant project developments.

17 **Q. What aspects of the project does Mr. Mullins challenge?**

18 A. The only aspect of the Ardmore project that Mr. Mullins challenges is the cost.
19 Based on this, he believes there is evidence of imprudence and recommends that
20 some of the costs for the project, about \$13.6 million, be disallowed. However,
21 Mr. Mullins does not adequately understand or account for the project drivers that

1 impacted the final cost for the project. Indeed, the documentation provided by
2 PSE demonstrates that the final project cost was not the result of “cost overruns”
3 as Mr. Mullins suggests, but rather was the result of a variety of factors not
4 unusual for a complex construction project.

5 **Q What concerns do you have with how Mr. Mullins determines and**
6 **substantiates the \$13.6 million he proposes to disallow?**

7 A. Despite PSE providing substantial documentation surrounding the Ardmore
8 project, Mr. Mullins calculated his suggested \$13.6 million disallowance based on
9 the difference between the \$39.5 million actual cost and a point in time
10 “planning” document that was updated with an estimate of \$25.9 million as of
11 October 7, 2010.²¹ Mr. Mullins’ reliance on this document is disingenuous and
12 should be rejected for several reasons. First, PSE’s planning documents are
13 updated periodically throughout a project, but are not intended to and do not
14 provide an accounting of current project status. To suggest that the document Mr.
15 Mullins relies on was intended to fully and completely document the final costs
16 for the project is nonsensical and was never the purpose of the document.
17 Second, Mr. Mullins overstates the information contained in the document by
18 asserting that the projected cost of \$25.9 million was when the “existing design

²¹ Exh. BGM-8.

1 and location of the substation were finally selected.”²² This is incorrect. In 2010,
2 while the final site was purchased, the design was not final and significant
3 planning had yet to occur. At that time, permits were not yet received to
4 appreciate the full impact of permitting requirements, material and construction
5 bids were not yet received, all construction easements had not yet been obtained,
6 and the added cost as a result of combining Interlaken nor the credit for the sale of
7 the property (\$3.6 million) was not included. Thus, Mr. Mullins reliance on this
8 document as evidence of a “cost overrun” is not credible.

9 **Q. Why did the costs for the project turn out to be higher than originally**
10 **anticipated?**

11 A. The cost increases for the Ardmore project were the result of an evolving scope of
12 work over time associated with changing requirements, stakeholder input,
13 property permitting costs, increased materials and construction costs, costs
14 associated with adding Interlaken, constraints and opportunities in the area, and
15 construction site conditions. Processes for approvals for budget and associated
16 scope changes were followed as documented in Project Change Requests and
17 were provided in PSE’s Response to ICNU Data Request No. 040, which Mr.
18 Mullins fails to reference. Please also see Exhibit CAK-8, which is a chronology
19 of the entire project cost and scope details.

²² Exh. BGM-1T at 52.

1 Mr. Mullins' use of the \$25.9 million planning estimate is inappropriate for the
2 reasons I have discussed. Despite the significant documentation provided in
3 discovery, he fails to understand the costs and drivers for this much needed and
4 complex project, and he relies on only a few statements from one post-project
5 continuous improvement review document²³ in his efforts to disallow \$13.6
6 million. When the documentation is viewed in its totality, it is clear that PSE
7 prudently managed the work on the Ardmore project.

8 **Q. Please provide in detail the increases in costs over time.**

9 A. The largest cost drivers of the project are related to site and right of way
10 conditions and permitting. *See* Exhibit CAK-8. In December 2010, PSE's
11 projected budget was \$26.6 million, the increase in the estimate as a result of
12 receiving SEPA Determination of Non-significance and preliminary direction
13 from the City of Redmond from which the previous estimate was based on
14 estimates at 30% design. In May 2011, PSE's projected budget increased to \$31
15 million due to additional substation design, material procurement, and the Notice
16 of Final Decision from the City of Redmond and Conditional Use Permit. In June
17 2011, the projected budget increased to \$35.3 million due to the numerous costs
18 associated with utility conflicts and additional pavement costs. In February 2014,
19 the close to final projected budget was \$39.2 million, which captured the
20 condemnation settlement for the additional transmission line easements needed

²³ Exh. BGM-10 at 7 (PSE Resp. to ICNU DR 091 Attach B).

1 and further impacts due to permitting relating to architectural pole. With many of
2 these cost drivers impacting the distribution feeders, the overall cost of the feeders
3 were about \$725 per linear foot of trench which is comparable or lower than the
4 cost of other projects in a similar urban environment. For example, PSE's
5 Lochleven feeder extension project, which was also located in Bellevue,
6 Washington, was completed in 2011 at a cost of about \$900 per linear foot of
7 trench.

8 **Q. Can you explain the construction requirements in Redmond over the course**
9 **of the Ardmore project that increased costs?**

10 A. Yes. The requirements for constructing in Redmond changed while the project
11 was in progress and after the planning document cited by Mr. Mullins. At the
12 outset, PSE coordinated with three jurisdictions and agencies to obtain the needed
13 approvals of fifteen permits such as SEPA determination, Conditional Use Permit,
14 Comprehensive Plan Consistency Review, and Design Review Board Approval.
15 The permitting requirements and costs for the project are not known prior to the
16 final approval and were not fully accounted for in the planning document cited by
17 Mr. Mullins. Preliminary assumptions about permit requirements were evolving
18 as PSE was finalizing its plans. For example, Redmond's Overlake Neighborhood
19 Plan was adopted in 2007 and the requirements of that plan and the corresponding
20 code amendments were contemplated in the early planning phases of Ardmore.
21 However, in 2010, Redmond commenced with an update to the city's
22 Comprehensive Plan and design guidelines for certain neighborhoods, which

1 changed the requirements. The Design Review process and standards that had
2 been in place since the 1980s were expanding as PSE's project moved through the
3 permit process which required PSE to integrate into the substation design all of
4 the streetscape standards, public trail provisions, provisions for plazas, open space
5 and public art that other commercial development was required to provide. The
6 architectural wall, green wall, artistic pole, gates and plaza were required by the
7 Design Review Board, and required for the approval of the Conditional Use
8 Permit. In addition, right-of-way and building permits were issued after land use
9 permits were issued for which added requirements became apparent only after
10 approval. Design decisions that simplified the permit process so that the new
11 station could be completed in a timely manner, garnered support from the cities of
12 Redmond and Bellevue, also enabled PSE to sell the Interlaken property.

13 **Q. What site conditions changed that impacted the final cost?**

14 A. In addition to the construction changes that occurred due to permitting
15 requirements, site conditions impacted construction as well, which increased
16 costs. For example, portions of the distribution lines exiting the substation were
17 rerouted to avoid costly and lengthy easement acquisition; subsurface and road
18 surface conditions were not accurately reflected in any records; the size of the site
19 required non-typical materials such as the use of Gas Insulated Switchgear
20 ("GIS") equipment rather than an open air ring bus and the addition of firewalls
21 between the transformers; and the expanded scope that combined Ardmore and

1 Interlaken substations, thereby eliminating maintenance and future update costs at
2 the Interlaken site.

3 **Q. Did PSE purchase materials before a final site was selected?**

4 A. Yes, PSE purchased materials before a final site was selected in a manner
5 consistent with standard practice. For example, PSE routinely purchases materials
6 such as 25 MVA transformers in bulk based on future needs to avoid project
7 delays and to serve as interchangeable spare equipment for other substations in
8 the event of an equipment failure. These materials are held in inventory until
9 construction begins. Due to urban nature of the area, permit requirements and the
10 size of available properties, some non-typical major equipment was needed such
11 as GIS. All major equipment including transformer, GIS, Metal Clad Switchgear,
12 MPAC, architectural walls and fire walls were competitively bid. PSE initiated
13 the purchasing process for long lead specialized equipment such as the GIS
14 equipment in 2008 upon securing the initial substation property. The final GIS
15 payment was made in 2011 after final design was completed. PSE did not need to
16 re-order any GIS equipment due to any of the scope changes already discussed.
17 The non-typical major equipment was more costly than initially estimated but the
18 timing of the purchases did not have a material impact as Mr. Mullin's asserts.

19 **Q. Did PSE manage the construction contract appropriately?**

20 A. Yes. PSE used a competitive bid process for selection of the substation contractor
21 and decisions were reviewed according to the management approval processes.

1 As with all construction projects, there are unanticipated issues that impact
2 contractors and construction plans. For this project, the issues impacting the
3 contractor and plans included: 1) schedule changes due to permit issuance
4 timeframes; 2) permit requirements that affected the scope and timing of the civil
5 work such as traffic control, work time allowances, backfill and restoration
6 restrictions, and city water main replacement; and 3) wet weather that impacted
7 site requirements, backfill and soil management. To manage these issues that
8 impacted the contractor, PSE required weekly meetings and reports with the
9 contractor, change approval requests, and, in some cases, a corrective action plan.
10 The issues such as permit requirements and site conditions did have an impact on
11 the project, but relative to its management of the contractor performance, PSE
12 managed and resolved most contracting issues during the project construction
13 phase, and the remainder before project closeout.

14 **Q. Would it have been reasonable for PSE to abandon the project when the**
15 **increase over the original plan was known?**

16 A. No. In addition to addressing the system improvements intended by original scope
17 of work, project benefits increased by absorbing the function of the Interlaken
18 substation eliminating the need to upgrade that station and incur additional cost.
19 For all the reasons already discussed, PSE's decision to continue forward was
20 prudent.

1 **VI. CONCLUSION**

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

3 A. Yes.