EXH. CAK-1T
DOCKETS UE-18___/UG-18___
2018 PSE EXPEDITED RATE FILING
WITNESS: CATHERINE A. KOCH

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of: **PUGET SOUND ENERGY** **Expedited Rate Filing**	**Docket UE-18____** **Docket UG-18____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

CATHERINE A. KOCH

ON BEHALF OF PUGET SOUND ENERGY

NOVEMBER 7, 2018

PUGET SOUND ENERGY

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF CATHERINE A. KOCH

I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is Catherine A. Koch. My business address is 355 110th Ave. N.E., Bellevue, Washington, 98009-5591. I am Director, Planning, with Puget Sound Energy ("PSE").

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

A. Yes, I have. It is Exh. CAK-2.

Q. What is the scope of your testimony in this proceeding?

A. My testimony in this proceeding will describe the significant transmission and distribution work performed by PSE between October 2016, the end of the test year in PSE's 2017 general rate case, and June 2018, the end of the test year in this proceeding, including the need for the work and the benefit to PSE's customers of the work. Additionally, I will describe PSE's initial Advanced Metering Infrastructure ("AMI") work.

II. SIGNIFICANT TRANSMISSION AND DISTRIBUTION WORK

Q. Please provide an overview of the significant gas and electric transmission and distribution work performed between October 2016 and June 2018.

A. PSE is dedicated to providing quality customer service and delivering energy safely, dependably, and efficiently, and the work PSE has performed over the past two years is intended to meet these goals. PSE has identified primary objectives for PSE's natural gas and electric system infrastructure, service, and operations. These objectives are: (i) maintain and improve customer and public safety, (ii) enhance system integrity and reliability, and (iii) meet the growth and service needs and expectations of our customers and communities. PSE has invested over $505 million in electric transmission and distribution infrastructure and over $386 million in gas distribution infrastructure between October 2016 and June 2018. Categories of significant investments greater than $100,000 are shown in Figure 1 and Figure 2.

Figure 1: Electric Capital Expenditures by Category

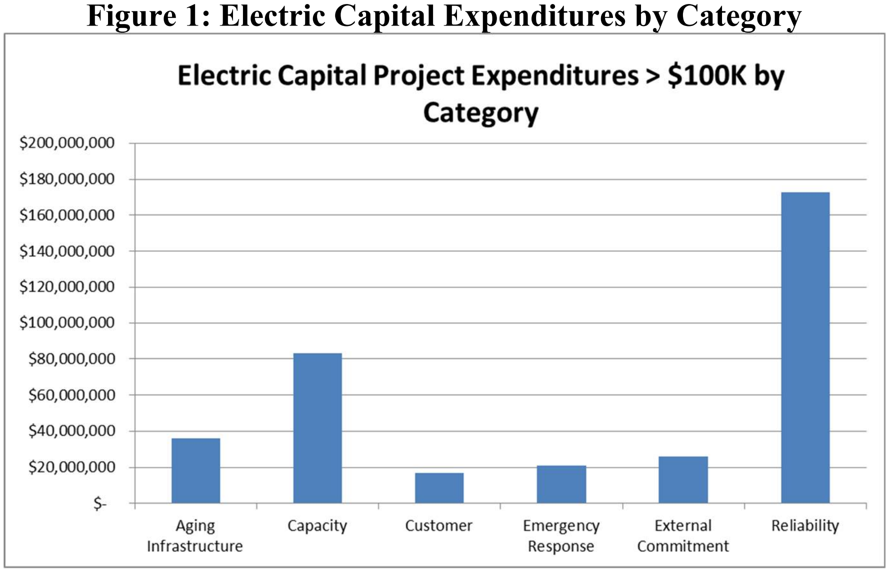
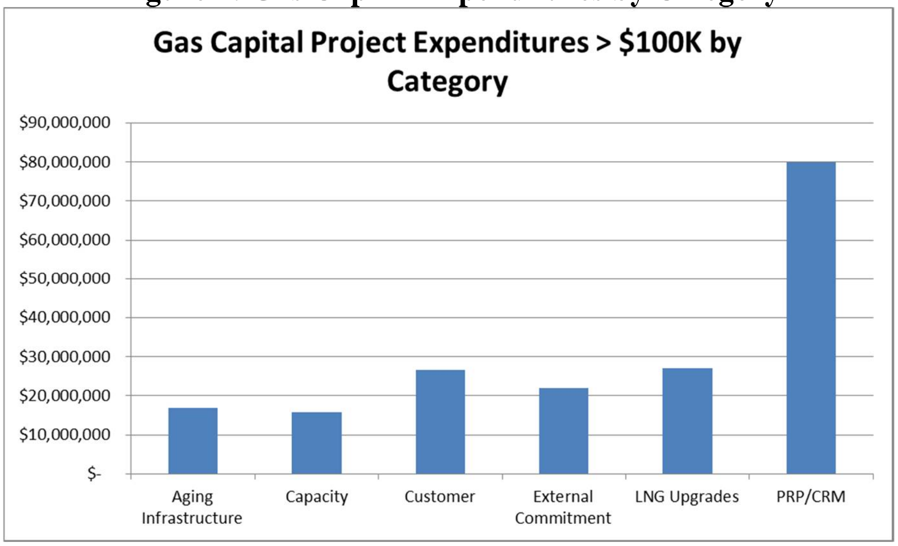


Figure 2: Gas Capital Expenditures by Category



This work included over $11.4 million in technology assets that increase the reliability of installed infrastructure through redundant and secure telecommuinications paths, IP (Internet Protocol) enabled voice and SCADA systems and technology required to provide the proper physical security protections.

To expand further on the work PSE has completed and for which PSE seeks recovery in this case, I will discuss the following: (A) major projects greater than $10 million; (B) electric reliability work[1] due to it comprising a significant portion of the electric investment; and (C) justification for all projects costing

[1] This discussion is primarily focused on the two programs identified in the Electric Reliability Plan and Cost Recovery Mechanism that was proposed in the 2017 general rate case. The proposed plan covered 2017 and 2018 work which PSE is working to complete as indicated in the rate case, although accelerated recovery through the Electric Cost Recovery Mechanism was not approved.

greater than $100,000. The gas pipeline replacement program is a significant portion of the gas distribution infrastructure investment that will not be discussed in my testimony, as it is recovered through the gas cost recovery mechanism. Please see the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, page 39-40, regarding the recovery of this portion of plant in service.

A. Major Projects Greater Than $10 Million

Q. Please describe the major projects with capital costs greater than $10 million.

A. There are five major projects with capital costs greater than $10 million: (1) Pierce County 230 kV Transmission and Substation; (2) LNG Pipeline and Gate Station; (3) Spurgeon Creek Substation; (4) Lakeside 115 kV Substation; and (5) Talbot Hill Substation. For these and other planned projects driven primarily by reliability and capacity, PSE follows a rigorous planning process that is described in Chapter 3 of the 2017 Service Quality and Electric Reliability Report submitted March 31, 2018 to the WUTC in Docket UE-072300.[2] As part of that planning process, PSE performs a needs assessment and a solutions analysis. My testimony describes for each project the need, alternatives considered, the cost, how the project is managed, how management is informed, and any major changes during the project lifecycle.

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[2] Chapter 3 of PSE's 2017 Service Quality and Electric Service Reliability Report is incorporated by reference into my testimony. https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=2460&year=2007&docketNumber=072300

1. Pierce County 230 KV Transmission and Substation

Q. Please describe the Pierce County 230 kV Transmission and Substation project ("Pierce 230").

A. Pierce 230 consists of 8.5 miles of new 230 kV transmission line on steel monopoles, extending from the White River transmission substation to the Alderton transmission substation. It also includes a new 230-115 kV transformer at Alderton, which establishes a second bulk power supply in Pierce County, with more secure and robust transmission support.

Q. Did PSE consider alternatives to the Pierce 230 project?

A. Yes. PSE investigated alternative solutions to building Pierce 230, including potential interconnection and the system impact to the Bonneville Power Administration's ("BPA") facilities. Based on the results of PSE's analysis of alternatives, Pierce 230 was the preferred project, as discussed in more detail later in my testimony.

Q. What was the timeline for the completion of Pierce 230?

A. The project need was first identified in 2005. After considering alternatives to the project, PSE decided to move forward with the Pierce 230 project in 2010. In 2011, a community advisory committee was established to vet the route and ensure all concerns were addressed. The project was placed in service in December 2017 with final restoration completed in June 2018.

Q. What was the final cost of the project?

A. The final cost of the project was $53,127,862. A portion of the cost was included in the 2017 general rate case associated with the 115 kV transmission line and substation work placed in service. PSE seeks recovery of the remainder of the project cost of $41.8 million relative to the 230 kV portion included in this case.

Q. Describe the system need for this project.

A. This project was driven by a capacity need for the bulk power delivery transmission system in Pierce County, which was approaching limits whereby meeting North American Electric Reliability Corporation ("NERC") planning standards could no longer be assured and customer reliability was at risk. Planning studies showed the bulk power 230-115 kV transformers at White River and certain 115 kV transmission lines could meet or exceed operating limits for single elements out of service (N-1 contingencies) and contingencies involving multiple elements out of service, such as bus outages, N-1-1, and N-2 events.

Q. Describe the alternatives evaluated and how this solution was chosen.

A. Four alternatives, including the selected alternative, were evaluated and are discussed below. For each of these four options, PSE included the assumption that cost-effective energy efficiency measures will be realized.

1) <u>Pierce 230 Project: A new 230 kV transmission line between White River and Alderton substations</u>. The selected option showed no negative impacts to the BPA transmission system, and it met PSE's long range 230 kV plan which was to extend a 230 kV backbone south of PSE's White River

substation to Pierce and Thurston counties. PSE then reviewed the proposed solution for route selection, with the assistance of an Advisory Committee composed of external stakeholders from the community, as well as Pierce County, the cities of Sumner and Puyallup, and the Washington State Department of Transportation. The route touches on all these jurisdictions. Ultimately, PSE selected the West Corridor route.

2) Expand Alderton substation to include a 230 kV yard, and loop in the existing White River-BPA South Tacoma transmission line into the station. PSE did not select this option because of negative impacts on the BPA transmission system, and it did not fully meet PSE’s long range 230 kV plan for Pierce and Thurston counties. The 230 kV backbone will potentially link major PSE transmission stations (White River, Alderton, Saint Clair, Spurgeon Creek) and regional BPA transmission stations (BPA Tacoma South, BPA Olympia) in Pierce and Thurston counties to provide for long term bulk power capacity need and improve bulk power reliability for PSE customers.

3) Expand the White River substation and install a third 230-115 kV transformer. PSE did not select this option because of its divese supply. White River would remain the only bulk power source for the county. Also, it did not fully meet PSE’s long range 230 kV plan for Pierce and Thurston counties.

4) Operate stand-by peaking unit at Frederickson as an interim step in the event of system load exceeding 5,200 MW. This option served only a

short term interim solution. In 2012, studies showed that in the absence of the White River Substation due to a failure of the aging transformers, the voltage requirments could not be met with dependency on a Frederikson generator for Pierce County.

Q. Did PSE re-evaluate the alternatives?

A. Yes. In 2012, PSE re-evaluated alternatives. Based on cost and the other factors discussed, the selected option remained the best alternative.

Q. Describe PSE's project management process that was used to manage this project.

A. PSE's project management process follows industry best practices and is based on our Infrastructure Project Lifecycle Phase/Gate Model, which includes five phases: Initiation, Planning, Design, Execution and Close-out. Each phase includes deliverables and activities that allow the project to progress through each phase by way of phase gate approvals. Each project is accompanied by a budget approval document in the form of a Project Change Request or a Corporate Spending Authorization.

Q. Describe how PSE kept management informed during this project.

A. PSE management reviewed Pierce 230 as project initiation began relative to establishing route selection and community involvement in 2011. Pierce 230 was approved by the executive level Energy Management Committee at the project planning phase in February 2013. PSE management gave approval to proceed into the execution phase as construction began in 2017. PSE tracked Pierce 230 within its Strategic Project Portfolio throughout the execution phase of the project.

Q. Please describe any material changes that impacted the project scope, schedule or budget.

A. In February 2013, the project was estimated to be between $40-$60 million. At the execution approval, the estimate was $45.7 million. The major changes to this project from $45.7 million to actual expenditure of $53.1 million are as follows:

1) Although PSE commenced a competitive bid process for the transmission line contract, PSE did not have recent historic cost data to use in setting its cost estimates. The final contract value exceeded PSE's estimate by approximately $2.5 million.

2) Between the design and execution phases of this project, PSE updated its financial system and accounting principles to achieve greater financial transparency. This resulted in an increase of roughly $2.6 million from the original estimate due to additional direct charges and associated overheads for the following reasons:

   i) A portion of costs that were previously captured in overhead assessments are now accounted for in direct project charges.

   ii) Overhead costs that were previously spread across the entire project portfolio are now calculated and spread according to the direct projects they support (electric, gas, generation, etc).

3) Due to the long lead time and concern regarding the aging equipment, the 230-115 kV transformer was delivered in 2010 and functioned as a system spare at the Alderton Substation until ready for permanent installation. The construction estimates did not include roughly $3 million for this material that was later allocated to the project when placed in final service.

2. Distribution Upgrades Related to Tacoma LNG Project

Q. Please describe the distribution system work associated with the Tacoma Liquified Natural Gas ("LNG") project.

A. PSE is installing an LNG facility in Tacoma for use both as a peak day resource and a source of LNG for an LNG fuel supply service. Exh. CAK-3 provides the Prefiled Direct Testimony of Larry Anderson, Exh. LEA-1T, submitted in Docket UG-151663, which provides more detailed information regarding the distribution work necessary. In 2015, Mr. Anderson testified that there were three primary area upgrades to connect the Tacoma LNG Project to the PSE gas distribution system:

1) <u>Four miles of new piping will connect the Tacoma LNG Facility to the PSE natural gas distribution system</u>. The new 16-inch line (i) supplies natural gas to the Tacoma LNG Facility for liquefaction and (ii) transports vaporized natural gas from the Tacoma LNG Facility to the distribution system when required to provide a peak day resource to the system.

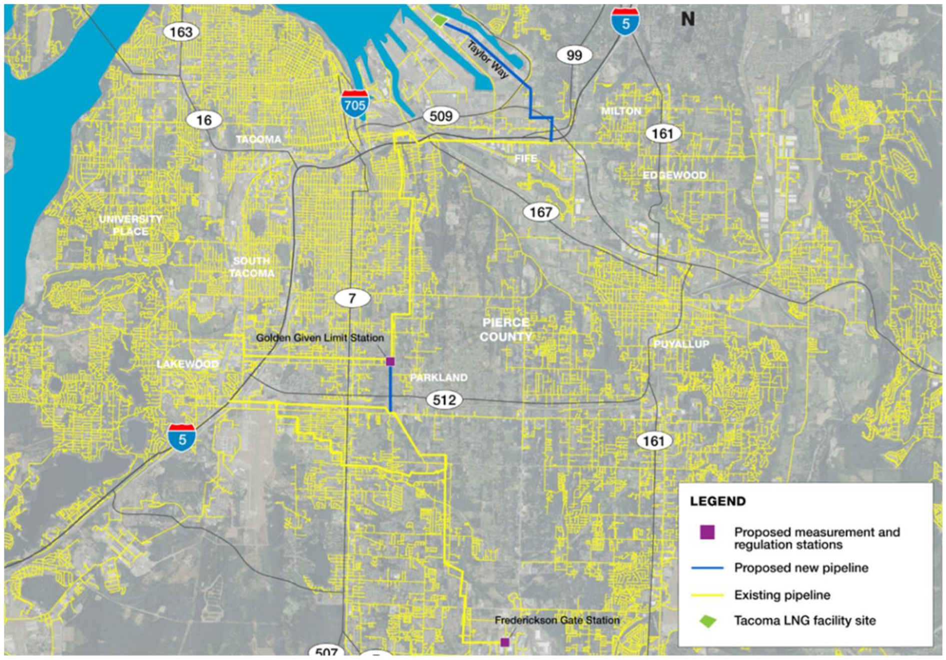
2) <u>One mile of 12-inch high pressure piping will be installed along Golden Given Road East, and PSE will install the new Golden Given Limit</u>

Station. The addition of the Tacoma LNG Facility natural gas load will exceed the capacity of the North Tacoma high pressure line unless reinforcement actions are taken to increase system capacity, which requires the installation of the one-mile of piping around the Golden Given Limit Station and the installation of the new limit station connecting the North Tacoma high pressure line and the South Tacoma high pressure line. This allows the South Tacoma high pressure line to take up more of the load and increase overall system capacity.

3) Upgrades to the Frederickson Gate Station. The prior Fredrickson Gate Station delivery capacity of 2.356 million cubic feet per hour (MMcf/h) was unable to supply 6 MMcf/h, which is necessary to meet anticipated loads, including the Tacoma LNG Facility, for the next 20 years.

Please see Figure 3 below for a map of the natural gas distribution system upgrades associated with the Tacoma LNG Project.

Figure 3. Map of Natural Gas Distribution System Upgrades



Q. What is the timeline for the completion of the LNG distribution upgrades project?

A. Construction on the four miles of new pipeline was completed and the pipeline was placed in service October 2017. (Item 1.) Construction on the upgrades to the Frederickson Gate Station was completed and the project was placed in service September 2017. (Item 3.) The one mile of 12-inch high pressure piping and new Golden Given Limit Station will be constructed as the LNG facility comes on line. (Item 2.)

Q. What was the final cost of the project?

A. The final cost of the work in service was $27,153,069. This includes the final cost of the four miles of the 16-inch pipeline (Item 1), which was $23,071,344; and the final cost of the Frederickson Gate Station Upgrade Project (Item 3), which was $4,116,259.

Q. Describe the system need for this project.

A. Prior to PSE considering the development of the Tacoma LNG Facility, the Gas System Integrity-Gas System Planning group identified system improvements that would be necessary to reliably serve anticipated future growth in the South Tacoma area during peak day conditions. For several years, PSE's ten-year plans have documented the necessary system improvements. The Tacoma LNG project modestly accelerates (by a little over a year) the need for natural gas distribution system upgrades that PSE has already identified as necessary in its ten-year planning processes.

Q. Describe the alternatives evaluated and how this solution was chosen.

A. As described in Exh. CAK-3 page 7, PSE's Gas System Integrity-Gas Planning group evaluates the capacity of PSE's natural gas system to reliably deliver natural gas to PSE's customers. The group analyzes the gas system and infrastructure using the most recent infrastructure load information. To build future system models, PSE adds anticipated growth, as necessary, to account for anticipated growth. PSE uses only firm loads for this analysis because all interruptible loads are assumed to be interrupted on peak days.

The Gas System Integrity-Gas Planning group considered several options for serving the natural gas load at the Tacoma LNG Facility. The Gas System Integrity-Gas Planning group considered increasing capacity from the existing

North Tacoma high pressure system and from the existing South Tacoma high pressure system. The Gas System Integrity-Gas Planning group determined that the more cost-effective and efficient approach was to reinforce the system from the south.

Q. Describe how PSE kept management informed during this project.

A. Using PSE's Project Lifecycle Model, management provides review and approvals. PSE management reviewed the initial project in July 2014 and again during the proceeding in UG-Docket 151663. PSE's Board of Directors conditionally approved the LNG project on September 22, 2016. Project updates were provided at monthly management and forecast meetings.

Q. Were there any material changes that impacted the project scope, schedule or budget?

A. No. The four mile, 16-inch pipeline and Frederickson Gate Station were estimated at $26.6 million and were completed within a reasonable variance.

3. Spurgeon Creek Substation

Q. Please describe the Spurgeon Creek Substation project ("Spurgeon").

A. Spurgeon is a greenfield capacity-driven distribution substation with future 115 kV transmission switching station capabilities.

Q. What was the timeline for the Spurgeon project?

A. The project was initiated in 2004 with an anticipated need date of 2009. The project was deferred for several years due to (i) a change in growth projections in

2007 caused by the economic downturn and (ii) the need to focus on another capacity project. The project resumed with public meetings in 2011 with an anticipated project start date of 2012. However, slower growth projections again delayed the project until 2015. The Spurgeon project was completed and placed in service June 2017.

Q. What was the final cost of the project?

A. The final cost of the project was $16,176,315.

Q. Describe the system need for this project.

A. There were several drivers of this project. First, the distribution substation and feeder capacity serving the local area was exceeding PSE's distribution planning guidelines and required additional distribution capacity in the area. Second, there was the need to improve the reliability for customers in the Olympia area. More than a third of the 120,000 customers in Thurston County were served by two transmission lines between the Olympia and St. Clair substations. Spurgeon sets the stage for PSE to improve transmission reliability in the area. With Spurgeon constructed, PSE will initiate future transmission projects to limit outage exposure to customers in the Olympia/Lacey area and establish a more redundant power supply transmission network for the county. Spurgeon secures a presence for future 230 kV expansion and bulk power capacity addition to meet long term growth in Thurston County.

Q. Describe the alternatives evaluated and how this solution was chosen.

A. Three alternatives, including the selected alternative, were evaluated. For each of these three options, PSE included the assumption that cost-effective energy efficiency measures will be realized.

1) Develop a new Spurgeon Creek transmission and distribution substation with provisions for 230 kV in the future. This alternative was selected because it meets the need objectives of the project, it meets PSE's long range plan to accomodate customer growth and improve reliability in the area, and the location has a close proximity to existing 230 kV transmission.

2) Defer the transmission switching portion of the station. This alternative was rejected because it delays the transmission reliability benefits. Additionally, this alternative was complicated by potential difficulties in acquiring transmission easements and higher costs associated with the acquisition of these easements.

3) Construct a new 230 kV transmission substation, at a separate undetermined location, in the future when needed. This alternative was rejected due to the uncertainty of finding an acceptable property in the future.

Q. Describe how PSE kept management informed during this project.

A. Using PSE's Project Lifecycle Model, management provides review and approvals of the project. The project was reviewed by management in June 2014 at the design phase.

Q. Were there any material changes during execution that impacted the project scope, schedule or budget? If so, describe.

A. No. In June 2014, the project was estimated at $16.4 million and was completed under this estimate.

<u>4. Lakeside 115 kV Substation</u>

Q. Please describe the Lakeside 115 kV Substation project ("Lakeside").

A. The Lakeside project consisted of rebuilding the existing 115 kV switching station from a main and auxiliary bus to a breaker-and-a-half bus configuration to improve reliability for customers in the Bellevue, Issaquah, Kirkland and Newcastle areas. The project also included construction of a new station control house.

Q. What was the timeline for the Lakeside project?

A. The Lakeside project was initiated in 2012 with an anticipated need date of 2015. Due to budget priority and adjacent system needs, it was delayed a couple of years and completed in October 2017.

Q. What was the final cost of the project?

A. The final cost of the project was $17,348,155.

Q. Describe the system need for this project.

A. The primary need for this project was to improve reliability, and it can be broken into three categories.

1) The structures, foundations and twelve circuit breakers required replacement due to aged condition. The existing breakers were between 35 and 50 years old, served a large number of stations and had seen a significant number of faults. In addition, multiple electromechanical relay packages needed replacement in the existing control house.

2) The bus work had aging structures and failing foundations. Additionally, the layout created reliability concerns, all of which could be improved while addressing the aging relays and breakers.

3) The single bus section breaker at Lakeside put all of the eleven 115 kV transmission lines at risk of opening in the event of a bus section breaker failure, which would drop service to thousands of customers. A bus fault or breaker failure could result in an outage to two substations and opening multiple transmission lines.

Q. Describe the alternatives evaluated and how this solution was chosen.

A. Six alternatives, including the selected alternative, were evaluated. For each of these six options, PSE included the assumption that cost-effective energy efficiency measures will be realized.

1) Rebuild the Lakeside 115 kV bus to breaker-and-a-half configuration. This option was selected because it optimized substation improvements while providing a more reliable substation configuration.

2) Rebuild the Lakeside 115 kV bus to a breaker-and-a-half configuration; construct the first half of the bus by 2017 and the second half after 2020 in a phased approach to allow for future transmission expansion in the area. This alternative was not as efficient as rebuilding all of the substation before other transmission system improvements.

3) Rebuild the Lakeside 115 kV bus to a breaker-and-a-half configuration after future transmission expansion in the area. This was not as efficient as rebuilding the substation before the future transmission expansion.

4) Use existing bus configuration, proceed with upgrades. Upgrades include: replace circuit breakers; install a second bus section breaker; replace all of the remaining electromechanical relays; extend the substation fence to the north and install a breaker off the north bus for capacitors; and replace the south dead-end structures and foundations. This option was rejected due to its benefit versus cost.

5) Rebuild the Lakeside 115 kV bus to a double-bus-double-breaker configuration. This option was rejected due to the shape and size of the substation property and location of existing 115 kV lines.

6) Rebuild the 115 kV switchyard at the pole yard property to the south of the existing Lakeside substation. This option was rejected because of transmission line congestion and unacceptable schedule durations.

Q. Describe how PSE kept management informed during this project.

A. Using PSE's Project Lifecycle Model, management provided review and approvals of the project. The project was approved by management to: (1) proceed to project planning in June 2014; (2) proceed to design in January 2015; and (3) proceed to execution in April 2016.

Q. Were there any material changes during execution that impacted the project scope, schedule or budget?

A. No. In April 2016, the project was estimated at \$19.1 million and was completed under the estimate.

5. Talbot Hill Substation

Q. Please describe the Talbot Hill Substation project ("Talbot").

A. Talbot is a complete rebuild of the 230 kV side of the substation. The project will rebuild the 230 kV substation into a double bus double breaker configuration. The project also includes construction of a new station control house and upgrades to the protection systems. Due to system constraints for when a planned outage can occur, the project was required to be built in two phases. Phase 1 included the north half of the bus, the new control house, and site improvements; Phase 2 includes the south half of the bus.

Q. Are the Phase 1 improvements to the Talbot project operating and providing service to customers?

A. Yes.

Q. What was the timeline for the Talbot project?

A. Talbot was initiated in 2015, and Phase 1 was completed in November 2017. Construction is ongoing and the rest of the project is scheduled to be complete in 2019. PSE is seeking recovery of the cost of Phase 1 in this case.

Q. What was the final cost of the project?

A. The final cost of Phase 1 of the project, including the new station control house, was $16,407,860.

Q. Describe the system need for this project.

A. There were four circumstances creating a need for this project.

1) The existing 230 kV bus at Talbot was divided into a north and south bus and separated by a normal open switch that could not be operated unless both buses were de-energized. This limited the operational capability and flexibility of the substation.

2) The existing 230 kV intertie lines between Talbot and BPA Maple Valley had no breakers on the PSE end of the line at Talbot which required that

the Talbot bus differential protection scheme[3] sense for faults all the way to the breaker on the Maple Valley end of the line. A line outage for either of the two intertie lines would take out the entire Talbot north or south 230 kV bus, which occurred three times in the past. Additionally, a single element failure (N-1 contingency) on either of the Talbot-Maple Valley 230 kV lines resulted in a total bus outage at Talbot and could have resulted in one of the Talbot 230 kV banks loading up to 90%.

3) The differential protection scheme was an old system with copper control wires run over public streets and under the Seattle water lines between Talbot and Maple Valley.

4) Taking a 230 kV line breaker out of service for maintenance resulted in that line being out of service due to the lack of an auxiliary bus. Today's NERC planning standards require the study of bus section breaker failures. A bus section breaker failure at Talbot would take out both sections of the 230kV bus and open five existing 230kV lines and two 230-115 kV transformer banks. The station was originally designed around 1960 for a future 230 kV auxiliary bus, a single 230kV section breaker on the main bus, and a 230 kV bus tie breaker, though these items have not been constructed.

[3] The purpose of a differential protection scheme is to protect equipment from damage or overloads caused by a fault. It operates by monitoring measuring points along a line to determine where a fault may have occurred and then instructing the breakers or other types of equipment to open to isolate customers or equipment.

Q. Describe the alternatives evaluated and how this solution was chosen.

A. Three alternatives, including the selected alternative, were evaluated. For each of these three options, PSE included the assumption that cost-effective energy efficiency measures will be realized.

1) Rebuild to a double bus double breaker configuration. This alternative was selected as it provides the most efficient electrical solution, it can be built within the existing station footprint, it eliminates 230 kV line crossings, reduces bus outage duration during construction, and allows for phased construction. It eliminates the switch, retires the old differential scheme, and allows for maintenance of breakers without taking a line outage.

2) Rebuild the existing main and auxiliary bus configuration to current standards and add back-to-back bus section breakers. This alternative provides an acceptable electrical solution, but was rejected because several unacceptable contingencies would result. Construction of this option would require an outage on the entire 230 kV side of the station, which would likely not be feasible due to system outage constraints. It would also require expansion of the south fence line of the station and multiple transmission line getaway crossings.

3) Rebuild to breaker and a half configuration. This alternative provides an acceptable electrical solution, but was rejected because (i) it would require significant expansion of the east fence line, impacting Seattle Public Utilities water lines and BPA; (ii) it presented the increased complexity of needing to cross multiple transmission line getaways leaving the

substation; and (iii) the expansion of the existing footprint would have triggered additional permitting requirements, increasing the risks to the project timeline.

Q. Describe how PSE kept management informed during this project.

A. Using PSE's Project Lifecycle Model, management provided review and approvals. The project was reviewed by management in June 2016.

Q. Were there any material changes during execution that affected the project scope, schedule or budget? If so, describe.

A. In August 2016, Phase 1 was estimated at $11.7 million. There were three changes to Phase 1 of this project that caused the cost to increase from the $11.7 million to the actual expenditure of $16.4 million as follows:

1) The City of Renton initially stated that a building permit was not needed for the new station control house structure. After construction was started, the city later determined that a permit was required, which stopped construction and delayed it several months resulting in the need to accelerate the work. This resulted in nearly $2 million of added labor and overtime.

2) Unforeseen circumstances arose during construction which resulted in additional scope and contractor costs. These changes included contaminated soils, additional transmission line relocation, and around the clock site security guard during construction due to vandalism and NERC requirements. Also, additional safety watches due to changes in safety

regulation interpretations regarding energized substations resulted in an increase of over $1.2 million.

3) Between the design and execution phases of this project, PSE updated its financial system and accounting principles to achieve greater financial transparency. This resulted in an increase of roughly $1.3 million from the original estimate due to additional direct charges and associated overheads for the following reasons:

   i) A portion of costs that were previously captured in overhead assessments are now accounted for in direct project charges.

   ii) Overhead costs that were previously spread across the entire project portfolio are now calculated and spread according to the direct projects they support (Electric, Gas, Generation, etc.).

B. System Infrastructure Placed in Service

Q. Please describe the system infrastructure that was placed in service between October 2016 and June 2018.

A. Since the 2017 general rate case, PSE placed in service over $505 million in electric transmission and distribution infrastructure as a result of almost 28,000 projects. PSE placed in service over $386 million in gas distribution infrastructure as a result of almost 32,000 projects. Please see the Prefiled Direct Testimony of Katherine J. Barnard, Exh. KJB-1CT, for more details about the overall plant.

Q. Please provide the justification for projects greater than $100,000.

A. Please see Exh. CAK-4, ERF Project Listing, for a detailed MS Excel spreadsheet of completed projects that were evaluated using PSE's investment Decision Optimization Tool ("iDOT") when proposed. The first worksheet of Exh. CAK-4 titled "List" includes (i) energy type, (ii) the project name, (iii) the costs inccurred between October 2016 and June 2018, (iii) the reason for or driver of the work, (iv) whether it is evaluated in iDOT as a specific project or program, and (v) the iDOT output of benefit-to-cost ratio ("B/C ratio") which is the resulting economic analysis for a given project. Some types of projects are similar in nature and managed as a program such as pole or underground cable replacements and, therefore, the B/C ratio will be the same for the majority of work within the program.

Q. What is iDOT?

A. PSE compares the relative costs and benefits of various solutions (i.e., projects) using iDOT. iDOT, as PSE has labeled it, is essentially PriceWaterhouse Cooper's Folio software, a project portfolio optimization and value-based decision analysis tool. iDOT allows us to capture project and program criteria and benefits and score them across multiple factors including reliability, safety, capacity addition, deferred future costs and external stakeholder inputs. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years. iDOT optimizes benefit and cost for a given financial portfolio. Ultimately, iDOT captures the economic justification to move forward within the constraints of the business.

Q. Are all projects evaluated through iDOT?

A. No. Work that is performed at the request of customers or third parties is not evaluated using iDOT but instead must meet PSE tariff requirements that evaluate customer contribution based on criteria set forth in the tariffs. Additionally, work that is a result of unplanned events such as (i) emergent and storm outage restoration work, (ii) external commitments and public improvement work due to franchise obligations, and (iii) compliance, meter reading operations, tools, security, and generation are not included in the iDOT evaluation as this work is not discretionary in nature.

C. Electric Reliability Work

Q. Please describe the work performed to improve electric reliability.

A. PSE has focused on two areas to improve electric reliability: (i) accelerated replacement of high molecular weight ("HMW") cables that are prone to failure, and (ii) the worst-performing distribution circuits.

1. Accelerated Replacement of HMW Cables

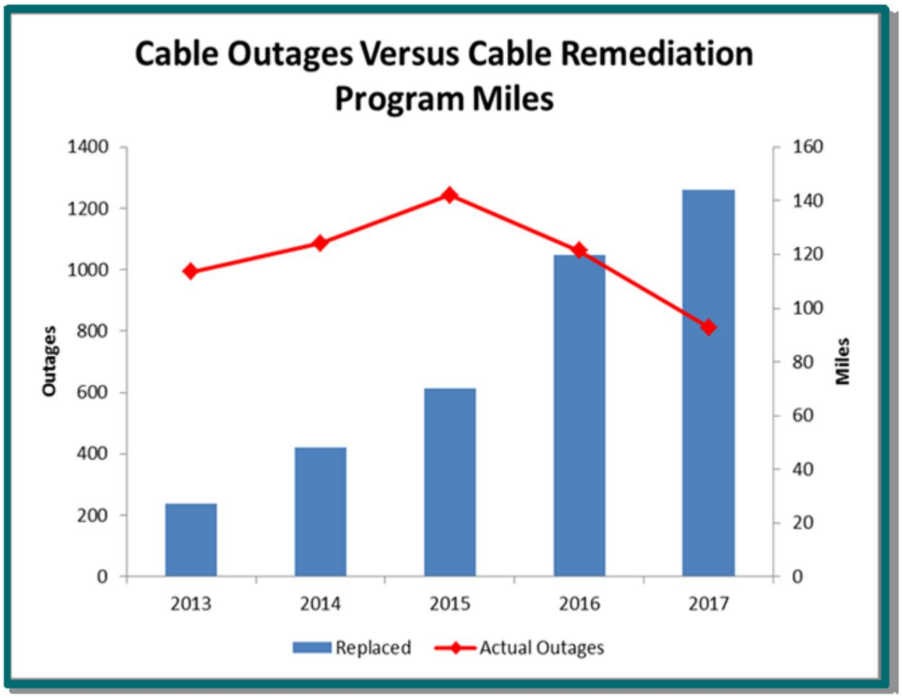
Q. Please describe the cable replacement work completed.

A. From October 2016 through June 2018, PSE has replaced approximately 251 miles of HMW cable that were prone to failure at a cost of approximately $84 million. This includes completion of more than 355 projects.

Q. Has reliability improved as a result of this work?

A. Yes. PSE began increasing the replacement of HMW cable in 2016. PSE has seen the number of outages decrease by 20% since 2015, as shown in Figure 4, below.

Figure 4: Cable Outages and Miles of Cable Replaced by Year



Additionally, PSE's system average interruption duration index ("SAIDI"), a metric that measures the average duration of outages, has decreased by over 2.5 minutes from 2015 to 2017. With respect to 2018, year to date, PSE has seen approximately an additional 1.0 SAIDI minute reduction from last year. PSE estimated that over the two year period 2017-2018, SAIDI would decrease by an average of 1.5 minutes per year as a result of accelerating the replacement of HMW cable. This reduction in the duration of outages is being realized.

2. Increased Focus on the Worst Performing Circuits

Q. Please describe PSE's work on the worst performing circuits.

A. In 2017, PSE focused efforts on improving reliability to the 135 distribution circuits within its electric service territory with the worst performance. From October 2016 through June 2018, PSE completed 77 projects on 54 circuits at a cost of $55.3 million.

Q. Has reliability improved as a result of this work?

A. In reviewing the 47 circuits that received significant focus in 2017, SAIDI performance is trending positive, with improvements on over 89% of them. Appendix N of PSE's 2017 Service Quality and Electric Service Reliability Report, provides detail of the work by circuit and notes that 12 circuits dropped off the list of the worst performing circuits.[4] As discussed previously, PSE's SAIDI performance is improving, and Figure 5 below compares the 2014-2018[5] SAIDI performance to the number of completed projects on the 47 worst performing circuits during that same time period.

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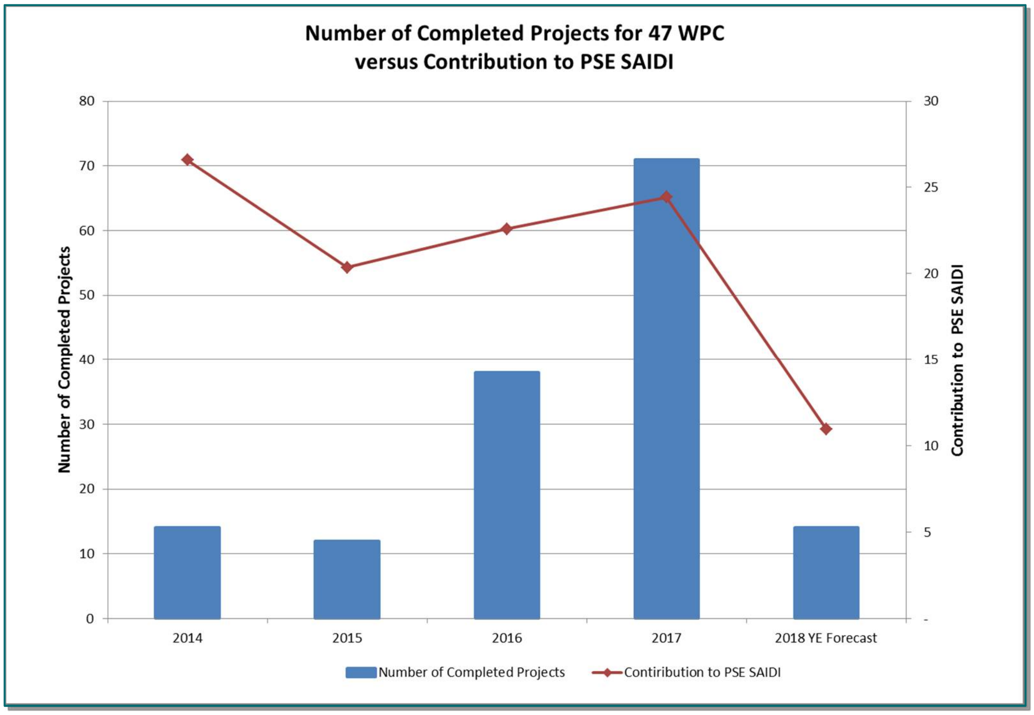
[4] Appendix N of PSE's 2017 Service Quality and Electric Service Reliability Report is incorporated by reference into my testimony. https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=2460&year=2007&docketNumber=072300

[5] Work on the noted 47 circuits occurred between 2014 and 2018 with significant focus in 2017.

Figure 5: SAIDI Results and Projects Completed on WPC



Q. Are there other ways PSE can measure the effectivness of these projects?

A. Yes. After projects are put into service, PSE performs a Reliability Improvement Verification, which is sometimes referred to as "backcasting," to confirm the expected benefits. The outages within the improved project area are typically reviewed several years after being placed in service to provide "outage opportunity" and to compare performance after the completion of the project to the outage history prior to the system improvement project. This verification helps to confirm the success of certain reliability strategies or provides insight on how to make adjustments and improvements in the future. The 2016 work will be backcasted in 2020, and the 2017 and 2018 work will be backcasted in 2021 and 2022.

III. ADVANCED METERING INFRASTRUCTURE

Q. Please describe the Advanced Metering Infrastructure project.

A. This project involves the installation of an advanced metering infrastructure ("AMI") communication network and metering equipment across PSE's electric and gas service territory to continue accurately billing for energy use for PSE's 1.2 million electric and 800,000 gas customers. Installation of the network began in 2016, providing service to new electric meters and gas modules in service beginning 2018. Full deployment of electric meters and gas modules will be completed in approximately 2023-2024. Currently, the projected cost of the total project is $473 million, $456 million of which will be capital and $17 million of which will be charged to operations and maintenance expense.

Q. Please describe what PSE is seeking to recover in this expedited rate filing.

A. PSE is seeking recovery of the communication network, command center software and hardware, and meter/module assets placed in service thus far, which totals $60,548,403 for assets placed in service between October 2016 and June 2018. PSE is not seeking pre-approval of work not yet completed. Because technology is a significant enabler to the successful completion of the AMI project, approximately $44.3 million of the expenditure was associated with technology assets including the core network and other required software and hardware systems. This technology platform allows for secure transfer of meter data between our customers and PSE and allows for integration of this data into PSE's meter data management, customer information and billing systems.

Q. Please describe the need for AMI.

A. PSE deployed its existing Automated Meter Reading ("AMR") network primarily between 1998 and 2001, and the design life was 15 years. The AMR network and module assets are approaching the end of their useful lives and require replacement in order to provide ongoing accurate energy billing for customers. Because AMR equipment is not a technology that the vendor or market is enhancing or supporting, as AMR equipment fails PSE must either refurbish the failed equipment or buy refurbished equipment. PSE was faced with the option to either refurbish the AMR system with the same limiting one-way technology or transition to more up-to-date, two-way AMI technology. After consideration of the options, PSE elected to move forward with installation of the AMI network.

Q. Please elaborate on the two-way communication that AMI provides.

A. AMI technology provides PSE with the ability to send and receive energy data. Additionally, the advanced analytics provided by AMI's two-way communications help PSE (i) operate the grid more efficiently and reliably, (ii) analyze usage in order to combat energy diversion, and (iii) forecast customer usage patterns to optimize energy supply and delivery or take the opportunity to update the system. AMI's two-way communication will benefit customers now and in the future with features such as advanced outage prediction and communication without customer calls, availability of load profile and demand information, prepay metering services, and ability to remotely disconnect and reconnect service for move-in/move-out. Also, the AMI network will allow for expansion and adaptability to evolving customer and business needs such as trends towards distribution automation and decreased energy usage through expansion of PSE's existing conservation voltage reduction ("CVR") program and emerging technologies over the next 15-20 years. The two-way communication required the installation of advance security software and encryption to provide the necessary cyber security for the network and meters/modules associated with risks not present with the one-way AMR system.

Q. Please describe the current status of the AMI project.

A. The AMI project requires deployment of (i) network devices, (ii) electric meters, and (iii) gas meter modules. PSE has deployed 2,136 network devices across its service territories. The deployed network devices are primarily in PSE's electric service only territory and PSE's combined gas and electric service territory. PSE is working with the 17 other electric companies in its gas service only territories to provide the various documents they are requesting prior to attaching PSE network devices on their poles. The network will be completed by 2020 with additional 6,124 network devices installed.

Electric meter and gas module deployment will roll out by zip code. Electric meter deployment began March 2018 and will be completed by July 2023. An average of 225,000 meters will be deployed each year with 155,000 expected by the end of December 2018. Gas module deployment began in June 2018 and will be completed by December 2022. An average of 193,000 modules will be deployed each year with 62,000 expected by end of December 2018.

Q. Please describe the benefits of the AMI project.

A. The principal benefits of the AMI project are as follows. First, the project will avoid the maintenance obligations that would otherwise increase if the existing AMR system is not replaced. PSE has experienced increasing failures of gas module batteries and AMR network nodes and software, along with continued capital investment in refurbished AMR modules, meters and network equipment. Second, the AMI project will allow PSE to more broadly implement the CVR program, which lowers customers' energy bills through reduction in supply voltage. AMI meters provide detailed voltage and load data. This information allows PSE to ensure voltage set points remain within required standards and, in many cases, identify opportunities for PSE to fine-tune its electricity delivery to provide conservation benefit with no impact to the customer. Third, the AMI project will result in avoided investment and maintenance needs for a separate distribution automation communication network by leveraging the AMI network as opposed to utilizing a hardwire communication system. Distribution automation requires communication between reclosers, switches, and the control center for automated operation; the wireless communication used by AMI can provide this. The wireless network used by the AMI meters will be leveraged and thus avoid costly installation of underground or overhead hard lines. The total benefit value of the AMI project is expected to be $668 million over the next 20 years.

There are other benefits resulting from the AMI project including: reduced capacity constraints and required distribution system upgrades due to reduced energy load from implementing end of line CVR; reduced billing and meter issues associated with exception work processes and call volume, gas zero-consumption based retro-bills, numerous estimated bills due to missing reads, more accurate demand billing, and reduction in lost or mixed meters; and finally, a metering platform that can enable dynamic or time of use rates and reduced infrastructure investment for a direct load control program in the future.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.