EXH. CAK-3
DOCKETS UE-19___/UG-19___
2019 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-19____** **Docket UG-19____**

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

CATHERINE A. KOCH

ON BEHALF OF PUGET SOUND ENERGY

JUNE 20, 2019

PUGET SOUND ENERGY

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF CATHERINE A. KOCH

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I. MAJOR PROJECTS GREATER THAN $10 MILLION OVERVIEW

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

A. There are six major projects with capital costs greater than $10 million: i) Pierce County 230 kV Transmission and Substation, ii) Spurgeon Creek Substation, iii) Lakeside Substation, iv) Talbot Hill Substation, v) White River-Electron Heights 115 kV Transmission Line, and vi) Bellingham-Sedro #4 115 kV Reconductor Transmission Line. For each project, my testimony describes the need, alternatives considered, how management was informed, and any major changes during the project lifecycle. 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 ensure risks are managed, costs are controlled, and benefits will be realized as the project progresses 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.

II. PIERCE COUNTY 230 kV TRANSMISSION AND SUBSTATION

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

A. The Pierce County 230 kV Transmission and Substation project ("Pierce 230") is located in the Sumner and Alderton areas of northern Pierce County. Pierce 230 consisted of installing 8.5 miles of new 230 kV transmission line extending from the White River transmission substation to the Alderton transmission substation. It also included an added 230 kV line bay at White River substation, substation improvements at Alderton substation including 115 kV bus upgrades and expanding the existing station footprint to support 230 kV infrastructure with a new 230-115 kV transformer, which established a second bulk power supply in Pierce County, with more secure and robust transmission support. Appendix A contains the Project Implementation Plan for Pierce 230.

Q. Is Pierce 230 operating and providing service to customers?

A. Yes.

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

A. This project was initiated in 2005. After considering alternatives to the project, PSE moved forward with Pierce 230 in 2010 with a community advisory group beginning in 2011. The 115 kV substation improvements at Alderton were completed in 2012 and the 230 kV substation expansion was completed in 2015. Pierce 230 work associated with the 230 kV transmission line was completed and placed in service December 2017 with final site restoration completed in June 2018.

Q. What was the final cost of Pierce 230?

A. The final cost of the project was $53.1 million without AFUDC. The costs associated with the Alderton substation work were recovered in the 2017 general rate case. PSE seeks recovery of the remainder of the project cost of $41,957,946 associated with the 230 kV transmission line.

Q. Describe the system need for Pierce 230.

A. The primary need for the project was capacity in the bulk power delivery transmission system in Pierce County, which was approaching limits whereby meeting NERC reliability standards would no longer be assured and customer reliability was at risk. The bulk power 230-115 kV transformers at White River and certain 115 kV transmission lines could exceed or were near operating limits for single and multiple element contingencies.

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

A. Four alternatives, including the selected alternative, were evaluated. PSE's solution required all identified needs be addressed and eliminated. In evaluating the alternatives, PSE prioritized the following key decision components: (i) availability of durable operating rights; (ii) minimizing environmental impacts; (iii) using existing corridors where possible; and (iv) minimizing impacts on the public such as schools and constructability. Additionally, PSE established a community advisory committee that evaluated alternatives.

1) Build a new 230 kV transmission line between White River and Alderton substations – This alternative was selected because it had no negative impacts to the Bonneville Power Administration ("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. The proposed solution was then reviewed for route selection with the assistance of the community advisory committee and ultimately, the West Corridor route was selected. In 2012, PSE re-evaluated alternatives and based on cost and the other factors, the selected alternative remained the best alternative.

2) Expand Alderton substation to include a 230 kV yard, and loop in the existing White River-BPA South Tacoma transmission line – This alternative was rejected 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.

3) Expand the White River substation and install a third 230-115 kV transformer – This alternative was rejected because of the lack of diverse supply as White River would remain as the only bulk power source for Pierce County. Also, it did not fully meet PSE's long range 230 kV plan for Pierce and Thurston Counties.

4) <u>Operate stand-by peaking generation units at Frederickson as an interim step in the event of system load exceeding 5,200 MW –</u> This alternative was rejected because it provided only a short term, interim solution, and in 2012, studies showed that in the absence of the White River substation, if a failure of an aging transformer or a bus contingency occurred, the minimum voltage requirements for Pierce County would barely be met with the Frederickson generator. Additionally, these units may not be available at the time of requirement for planned or emergency outage support.

Q. What benefits does Pierce 230 provide for customers?

A. This project improved reliability and capacity for over 100,000 Pierce County customers, improved bulk power supply reliability, and resolved capacity limitations of the existing bulk power supply to meet NERC reliability standards for bulk electric system performance. The new 230 kV transmission feed to the Alderton substation removed capacity constraints on the 115 kV lines and added operating flexibility for scheduling outages, and improved reliability by providing major support to the Alderton substation for forced outages during storms.

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

A. Using PSE's Project Lifecycle Model, management provided review and approvals for the project. This project was reviewed by management in 2011 as project planning began relative to establishing route selection and community involvement, in February 2013 by the executive level Energy Management

Committee to proceed to the project planning phase, and in January 2017 to proceed to the execution phase. Pierce 230 was tracked within PSE's Strategic Project Portfolio throughout the execution phase of the project.

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

A. Yes. In February 2013, this project was estimated at $40-$60 million. At the execution approval, the estimate was $45.7 million without AFUDC. The major changes to this project that increased the cost from $45.7 million to the 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 due to the fact that PSE does not regularly construct 230 kV infrastructure. The final contract 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 and more accurate and refined allocation of direct and overhead costs to specific projects. This resulted in an increase of roughly $2.6 million from the original estimate due to additional direct charges and associated overhead costs that were previously spread across the entire project portfolio and 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 Pierce 230 was placed in service.

Q. Have the benefits from Pierce 230 been realized?

A. Yes. Powerflow studies show that the bulk transformer capacity addition at Alderton solves capacity limitations at the White River substation under multiple contingencies from up to a maximum overload of 108 percent to 60 percent of the bulk transformer emergency loading limit at PSE forecasted peak winter load levels of 5,000 MW or more. Overloads on 115 kV lines between the Alderton and White River substations under multiple contingencies were mitigated to below line normal ratings.

III. SPURGEON CREEK SUBSTATION

Q. Please describe the Spurgeon Creek substation project.

A. The Spurgeon Creek substation project ("Spurgeon") is located in the East Olympia area of Thurston County. Spurgeon consisted of building a new distribution substation with future 115 kV transmission switching station capabilities. Appendix B contains the Project Implementation Plan for Spurgeon.

Q. Is Spurgeon operating and providing service to customers?

A. Yes.

Q. What was the timeline for Spurgeon?

A. This project was initiated in 2004 with an anticipated need date of 2009. The project was delayed 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 but slower growth projections again delayed the project until 2015. Spurgeon was completed and placed in service June 2017.

Q. What was the final cost of Spurgeon?

A. The final cost of the project was $16,176,316.

Q. Describe the system need for Spurgeon.

A. There were several needs for this project. First, the distribution substation and feeder capacity serving the area required additional distribution capacity. Second, there was the need to improve reliability for customers as 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. Third, with Spurgeon constructed, PSE can 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. Finally, Spurgeon also 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. PSE's solution criteria required all identified needs be addressed and eliminated.

1) <u>Build a new Spurgeon Creek transmission and distribution substation with provisions for 230 kV in the future –</u> This alternative was selected because it fully met the project needs, including PSE's long-range plan to accommodate customer growth and improved reliability in the area, and the location was close to existing 230 kV transmission. The selected alternative provided greater distribution feeder capacity and operating flexibility than the other two alternatives, which would add station capacity at existing sites.

2) <u>Defer the transmission switching portion of the station –</u> This alternative was rejected because it delayed the transmission reliability benefits and was complicated by potential difficulties in acquiring future transmission easements and higher costs associated with the acquisition of these easements in the future.

3) <u>Build a new 230 kV transmission substation, at a separate undetermined location, in the future when needed –</u> This alternative was rejected because of the uncertainty of finding an acceptable property in the future.

Q. What benefits does Spurgeon provide for customers?

A. This project improved Olympia area capacity and reduced customer interruptions due to having additional circuit and substation capacity in the area, which improves system redundancy and flexibility. Spurgeon also set the stage for future transmission reliability improvement projects such as sectionalizing the Olympia-St. Clair #1 115 kV line by looping the existing line through Spurgeon, as well as extending a second transmission feed to the Airport substation, which will benefit approximately 30,000 customers. Finally, a new 115 kV interconnection of Spurgeon to BPA Olympia (via Airport substation) will help meet NERC reliability requirements. Spurgeon also secures presence for future 230 kV bulk power capacity addition to serve long term capacity needs of Thurston County.

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

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in June 2014 to proceed to 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, this project was estimated at $16.4 million without AFUDC and was completed under this estimate.

Q. Have the benefits from this project been realized?

A. Yes. Additional station and feeder capacity added by this project reduced feeder loading on all circuits in the substation group area to below 400 amps. Having a circuit below 400 amps makes it possible to pick up half of the customers on an adjacent circuit during an outage. This reduces customer interruptions by allowing faster restoration times. This project also reduced loading on one of the substations in the study group (Lacey) by 35 percent. This additional capacity now allows this station to pick up some adjacent station load where it was unable to before the project.

IV. LAKESIDE SUBSTATION

Q. Please describe the Lakeside substation project.

A. The Lakeside substation project ("Lakeside") is located in the Bellevue area of King County serving customers in the Bellevue, Issaquah, Kirkland and the Newcastle area. Lakeside consisted of rebuilding the existing 115 kV switching station to a breaker-and-a-half bus configuration and included construction of a new station control house. Appendix C contains the Project Implementation Plan for Lakeside.

Q. Is Lakeside operating and providing service to customers?

A. Yes.

Q. What was the timeline for Lakeside?

A. This project was initiated in 2012 with an anticipated need date of 2015. The project was delayed due to other system priorities. Lakeside was completed and placed in service October 2017.

Q. What was the final cost of the project?

A. The final cost of the project was $17,046,461.

Q. Describe the system need for Lakeside.

A. The primary need for this project was to improve reliability. First, due to aging infrastructure, the structures, foundations and twelve circuit breakers required replacement and had experienced a significant number of faults. Also, multiple electromechanical relay packages needed replacement in the existing control house and the bus work had aging structures and failing foundations. Second, the layout created reliability concerns, all of which would be improved while addressing the aging relays and breakers. Third, the single bus section breaker at Lakeside would 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.

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

A. Six alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed and eliminated while maximizing construction efficiency to accommodate future transmission expansion in the area.

1) Rebuild bus to breaker-and-a-half configuration prior to other planned transmission expansion in the area – This alternative was selected because it addressed all of the aging and outdated equipment and infrastructure while providing a more reliable substation configuration and utilizing the existing substation footprint. It also allowed for the security and drainage systems to be updated to current standards. Transmission lines needed to be temporarily re-routed to maintain a safe and reliable system during construction. There was considerable congestion of transmission lines running in and out of the station on the north and south sides, and this alternative provided the necessary flexibility and space to construct safely while maintaining reliability for customers.

2) Rebuild 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 rejected because it was not as efficient as rebuilding the entire substation before other transmission system improvements. Phasing the project by several years created multiple challenges such as working around the existing transmission congestion and partially upgraded site drainage. It required extending the life of already aged infrastructure and did not realize the full benefits of a station rebuild with only rebuilding half of the station.

3) Rebuild bus to a breaker-and-a-half configuration after future transmission expansion in the area – This alternative was rejected because it was not as efficient as rebuilding the substation before the future transmission expansion, and it did not address the aging infrastructure within the station in a timely manner.

4) Use existing bus configuration, proceed with upgrades – This alternative was rejected because of the low benefit versus cost as the aging infrastructure within the Lakeside substation required several retrofits and equipment upgrades which included circuit breaker replacements, installation of a second bus section breaker, replacement of all of the remaining electromechanical relays, extension of the substation fence to the north, installation of a breaker off the north bus for capacitors, replacement of the south dead-end structures and foundations, and other site improvements, all of which did not bring the benefits gained by the selected alternative.

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

Q. What benefits does Lakeside provide for customers?

A. This project improved transmission reliability to approximately 114,000 customers in the Eastside area by reduced failure exposure from eleven 115 kV transmission lines down to two lines in the event of a bus section breaker failure. The replacement of eleven aging circuit breakers also reduced the likelihood of a breaker failure. The new Lakeside layout accommodated future transmission expansion by adding additional line bays and space for capacitors.

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

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management to proceed to the project planning phase in June 2014, in January 2015 to proceed to the design phase, and in April 2016 to proceed to the execution phase.

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

A. No. In April 2016, this project was estimated at $19.1 million without AFUDC and was completed under the estimate.

Q. Have the benefits from this project been realized?

A. Yes. This project is providing improved operational flexibility and transmission reliability to approximately 114,000 customers in the Eastside area. The replacement of twelve at-risk aged 115 kV oil breakers has greatly reduced the likelihood of a breaker failure at Lakeside, impacting thousands of customers radially fed.

V. TALBOT HILL SUBSTATION

Q. Please describe the Talbot Hill Substation project.

A. The Talbot Hill Substation project ("Talbot") is located in Renton and serves south and central King County. Talbot consisted of rebuilding the 230 kV side of the substation into a double bus, double breaker configuration and included construction of a new station control house and upgrades to the protection systems. Due to system constraints for when a planned outage can occur, Talbot was required to be built in phases: Phase I was the north half of the bus, the new control house, and site improvements and Phase II was the south half of the bus. Phase III was not included in the original scope of work. The need for Phase III was identified by BPA towards the end of Phase I in 2017 and added to the project in 2018. An issue was identified by BPA that showed a potential for fault current to have the ability to bypass the existing current limiting reactors within the BPA substation once PSE's breakers were energized on the newly configured double bus, double breaker. The solution was to add six current limiting reactors on the Talbot Hill-Maple Valley #1 and #2 230 kV transmission lines that interconnect PSE's substation with BPA's Maple Valley substation. This work is currently estimated to increase the total project cost by $5.5 million and is scheduled to be complete in 2020. Appendix D contains the Project Implementation Plan for Talbot.

Q. Is Talbot operating and providing service to customers?

A. Yes. Phase III discussed above is expected to be in service in 2020.

Q. What was the timeline for Talbot?

A. This project was initiated in 2015. Phase I was completed and placed in service November 2017 and Phase II was completed and placed in service December 2018. Phase III is planned for 2020.

Q. What was the final cost of Talbot?

A. The final cost was $22,634,159. The estimated total cost including the remaining Phase III work is $28.2 million.

Q. Describe the system need for Talbot.

A. There are several needs for this project. First, the existing 230 kV bus at Talbot that was divided into a north and south bus and separated by a normal open switch could not be operated unless both buses were de-energized. This limited the operational capability and flexibility of the substation. Second, 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[1] 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. The differential protection scheme was an old system with copper control wires

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[1] 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.

run over public streets and under the Seattle water lines between Talbot and Maple Valley. Third, 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.

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

A. Three alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed and eliminated with consideration of cost benefit for maximum flexibility and reliability in the operation of the Talbot substation and related infrastructure along with minimizing the risk to project completion and cost effectiveness.

1) <u>Rebuild to a double bus double breaker configuration –</u> This alternative was selected because it provided the most efficient electrical solution, could be built within the existing station footprint, eliminated 230 kV line crossings, reduced bus outage duration during construction, and allowed for phased construction. It also eliminated the bus section switch, retired the old differential scheme, and allowed for maintenance of breakers without taking a line outage. The double bus, double breaker rebuild was the least cost alternative with the most operability.

2) <u>Rebuild the existing main and auxiliary bus configuration to current standards and add back-to-back bus section breakers –</u> This alternative provided an acceptable electrical solution but was rejected because of several unacceptable contingencies. Construction required an outage on the entire 230 kV side of the station, which would likely not be feasible

due to system outage constraints. It required expansion of the south fence line of the station and multiple transmission line getaway crossings.

3) <u>Rebuild to breaker and a half configuration –</u> This alternative provided an acceptable electrical solution but was rejected because (i) it required significant expansion of the east fence line, impacting Seattle Public Utilities water lines and BPA; (ii) presented increased complexity of needing to cross multiple transmission line getaways leaving the substation; and (iii) triggered additional permitting requirements, increasing the risks to the project timeline.

Q. What benefits does Talbot provide for customers?

A. This project provided additional flexibility in the operation of the substation and reduced exposure during outage conditions. Breaker failures no longer result in complete bus outages and a 230 kV bus outage no longer cause outages to the transmission lines.

Additionally, as part of the rebuild, breakers were added to two BPA Maple Valley 230 kV intertie transmission lines. This allowed for a fault on the interties to no longer result in a bus outage, only effecting the intertie line. The protection changes associated with the addition of the breakers brought the relays and protection to current industry standards and best practices, and the replaced aging infrastructure improved reliability to the substation operation and overall connected system.

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

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in January 2015 to proceed to the design phase, in June 2016 for Phase I to proceed to execution phase, in April 2018 for Phase II to proceed to execution phase, and again in November 2018 to add the Phase III scope of work to the project.

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

A. Yes. In August 2016, Talbot was estimated at $16.5 million without AFUDC. There were four material changes during Phase I and Phase II that increased the project cost to $22.6 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 the project several months resulting in the need to accelerate the work, as well as triggering additional jurisdictional fees. This resulted in over $2 million of added labor and overtime, as well as a frontage improvement fee.

2) Unforeseen circumstances arose during construction which resulted in additional scope and contractor costs. These changes included contaminated soils, additional drainage and foundation work, additional transmission line relocation, and around the clock site security guard

during construction due to vandalism and NERC requirements. These changes resulted in an increase of over $1.7 million.

3) Between the design and execution phases of this project, PSE updated its financial system and accounting principles to achieve greater financial transparency and more accurate and refined allocation of direct and overhead costs to specific projects. This resulted in an increase of roughly $2 million from the original estimate due to additional direct charges and associated overhead costs that were previously spread across the entire project portfolio and are now calculated and spread according to the direct projects they support (electric, gas, generation, etc.).

4) When the double bus, double breaker configuration was chosen for the substation rebuild, coordination with BPA resulted in identification of an issue where BPA's fault protection equipment would be bypassed due to the configuration. PSE entered into an agreement in May 2017 (Agreement #16TP-11033) to cost share with BPA in the amount of approximately $60,000 for scoping the mitigation needed to protect BPA equipment at their Maple Valley substation. In 2018, BPA commenced planning for the line and bus relay upgrades that would be needed at the Maple Valley substation due to the Talbot Hill substation upgrades. PSE entered into a cost share agreement (Agreement # 18TP-11496) and paid $253,800 to upgrade the interconnected relays between the substations and maintain dedicated positions on the BPA auxiliary bus in case of line outages. Neither of these costs paid to BPA were included in the project

cost estimate. This resulted in a total of $313,800 of added cost to the project.

Q. Have the benefits from Talbot been realized?

A. Some benefits have been realized to date. The updated relays and protection schemes are in service in the upgraded control house, as are the breakers on the 230 kV intertie transmission lines between the Talbot substation and BPA's Maple Valley substation. Now, an outage or fault on the Talbot – BPA Maple Valley lines will no longer result in a bus outage. The full benefit will not be realized until all of the breakers are closed in, which requires completion of Phase III, which consists of installing the current limiting reactors on the intertie lines.

VI. WHITE RIVER-ELECTRON HEIGHTS 115 kV TRANSMISSION LINE

Q. Please describe the White River-Electron Heights transmission project.

A. The White River-Electron Heights transmission project ("White River-Electron") is located in the Alderton and Bonney Lake areas of Pierce County and serves customers in the Bonney Lake, Lake Tapps and Enumclaw areas. White River-Electron consisted of rebuilding the White River-Electron Heights-Krain Corner 115 kV transmission system such that it split the three-terminal line into two separate lines. Phase I of the project added a new four-mile 115 kV line from the Rhodes Lake substation to the Alderton substation, which split the three-terminal line into two lines. Phase II of the project split and re-routed 3.2 miles of one of these lines into two separate line segments, White River-Alderton #1 115 kV and

Alderton-Krain Corner 115 kV. Appendix E contains the Project Implementation Plan for White River-Electron.

Q. Is White River-Electron operating and providing service to customers?

A. Yes.

Q. What was the timeline for the completion of White River-Electron?

A. This project was initiated in 2002. Phase I was completed and placed in service October 2014. Phase II was completed and placed in service October 2018. The final activities of this project, which includes mitigation planting, permit closeout, and customer reimbursement for crop loss during construction, will be completed in the fall 2019.

Q. What was the final cost of White River-Electron?

A. The final project cost of Phase I and Phase II was $20 million. The costs associated with Phase I of the project were included in the 2017 general rate case. The final cost of Phase II of the project was $8,755,773 as of December 31, 2018, with final mitigation and closeout costs expected in late 2019 to be an additional $140,000.

Q. Describe the system need for White River-Electron.

A. There were several needs for this project. First, the White River-Electron Heights-Krain Corner 115 kV line was vulnerable to storm-related outages due to its combined 37 miles of exposure and three terminal configuration, and a reliability improvement was needed for the approximately 25,000 customers served by this line. Second, load growth in the Bonney Lake and Lake Tapps area of Pierce County required capacity improvements.

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

A. Three alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed and eliminated, specifically the customer reliability objectives and PSE's long-term transmission reliability objectives in Pierce County.

1) <u>Sectionalize the three-terminal line and route three-line sections to Alderton –</u> This alternative was selected because it fully met the project needs of transmission reliability and capacity. This segmented the customer load from one line servicing 25,000 customers to three lines serving 15,000, 6,000, and 4,000 customers, respectively. This also supported the long-term planning efforts for the Pierce County electric system.

2) <u>Sectionalize the three-terminal line and route one new line section to Alderton –</u> This alternative was rejected because it only partially met customer reliability objectives of the project and about 10,000 customers could continue to experience three to four outages per year.

3) <u>Install 115 kV breakers at Bonney Lake, Rhodes Lake and Osceola –</u> This alternative was rejected because it did not meet the near and long-term goals of the project or meet the system needs in the area. It leaves the

three-terminal connection in place without interconnection to a second 230kV bulk power source at Alderton.

Q. What benefits does White River-Electron provide for customers?

A. This project improved transmission reliability for approximately 25,000 customers served from five distribution substations in central Pierce County. The project better integrated the Alderton bulk power source to the Pierce County 115 kV transmission system and two of the three new lines out of Alderton are directed to the Bonney Lake/Lake Tapps area to provide new transmission capacity to support future area load growth.

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

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. Phase I of the project was reviewed by management to proceed to the execution phase in February 2014, in December 2014 to proceed to the close out phase for Phase I and for continuation of Phase II, and in May 2018 for Phase II to proceed to the execution phase.

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

A. No. In May 2018, the total lifetime project cost of Phase II was estimated at $8.2 million without AFUDC. The final project cost at the end of 2018 was $8.4 million without AFUDC and was completed within a reasonable variance.

Q. Have the benefits from this project been realized?

A. Yes. With the project in-service, transmission reliability has improved for the five distribution substations in Bonney Lake/Orting Valley area of central Pierce County. Transmission outage exposure was reduced for the Bonney Lake substation (~6,000 customers) from 17 miles to five miles, the Osceola substation (~4,000 customers) from 17 miles to eight miles, and the Orting Valley substations of Rhodes Lake, Knoble and Orting (~14,000 customers) from 17 miles to four miles. The project provides interconnection to a second 230 kV bulk power source at Alderton, thereby increasing the redundancy of the transmission network serving Pierce County.

VII. BELLINGHAM-SEDRO #4 115 kV RECONDUCTOR TRANSMISSION LINE

Q. Please describe the Bellingham-Sedro #4 Reconductor Transmission Line project.

A. The Bellingham-Sedro #4 Reconductor Transmission Line project ("Sedro #4") is located in western Whatcom and Skagit Counties serving Burlington and Sedro Woolley. Sedro #4 consisted of rebuilding and reconductoring the existing 24-mile-long Sedro Woolley-Bellingham #4 115 kV line. The line helps connect the Skagit County and Whatcom County 115 kV systems together and directly feeds two distribution substations, Alger and Norlum. To coordinate concurrent distribution system upgrades, this project was constructed in five phases: Phase A includes approximately four miles of the line in Skagit County; Phase B includes approximately seven and a half miles of the line in Skagit County; Phase C includes approximately six miles of the line in Skagit and Whatcom Counties; Phase D includes approximately six miles of the line in Whatcom County; and Phase E includes rebuilding the final a half mile of the line in Skagit County. Appendix F contains the Project Implementation Plan for Sedro #4.

Q. Is Sedro #4 operating and providing service to customers?

A. Partially. Phases A and B are operating and providing service to customers. Phases C, D and E are not.

Q. What was the timeline for the completion of Sedro #4?

A. This project was initiated in 2010. Phase A was completed and placed in service February 2018, and Phase B was completed and placed in service December 2018. Phase C is planned for 2020, and Phases D and E are planned for 2021.

Q. What was the final cost of Sedro #4?

A. The final cost of Phases A and B of this project was $10 million without AFUDC. PSE is seeking recovery of $8,079,838 in this rate case, as lagging contractor invoices and control zone mitigation costs have been incurred in 2019. The estimated total cost of the project, including all five phases, is $23 million without AFUDC.

Q. Describe the system need for Sedro #4.

A. There were several needs for this project. First, the low capacity line ratings would cause the line to exceed its allowable capacity ratings for several contingencies and would limit generation capacity in Whatcom and Skagit

Counties. The small copper wires also would cause high line losses and the aging infrastructure would lead to extended outages.

Second, the low capacity of the Bellingham-Sedro Woolley #4 line caused constraints on regional power flows for over twenty years due to the parallel higher-voltage transmission line, which required PSE to protect the line from loading above its allowable limits by automatically opening the Sedro Woolley substation circuit breaker. Opening the breaker and subsequently the line reduced system reliability in both Whatcom and Skagit Counties, including the Norlum and Alger substations. Additionally, the 6,240 customers served from the Norlum and Alger substations were at an increased risk of outage during this time as each substation has only one transmission source.

Third, the aged equipment of the line contributed to outages as there were 27 momentary outages and four sustained outages in the five years prior.

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

A. Three alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs to be addressed and eliminated including the existing line's low capacity, upgrading the aging infrastructure of the line, and addressing the thermal line loading limitation.

1) <u>Rebuild the 115 kV transmission line –</u> This alternative was selected because it addressed both the capacity deficiency and the reliability problems related to the aging infrastructure for the most economical cost. It included replacing all of the aging wood poles and upgrading the

conductor size, which addressed the line loading and reliability issues of the line.

2) <u>Maintain existing transmission line, replace bad order poles and keep Corrective Action Plan ("CAP") –</u> This alternative was rejected because it (a) did not decrease the number of line outages; (b) increased maintenance activities and costs; (c) reduced reliability to both counties due to the line having the potential to being forced out of service from the CAP which is an over-current protection scheme that would automatically open the line at Sedro Woolley substation to prevent it from overloading; (d) lowered reliability to the Alger and Norlum substations; and (e) did not eliminate the line overloads or the existing aging infrastructure.

3) <u>Build a new 115 kV transmission line –</u> This alternative was rejected because of its high cost from purchasing land and easements for a new right-of-way ("ROW"), the associated permitting challenges with a new ROW, and it did not address the aging infrastructure of the existing transmission line.

Q. What benefits does Sedro #4 provide for customers?

A. This project improved capacity, and reliability, and reduced operating costs through replacement of deteriorating infrastructure. Replacement of the aging infrastructure reduced the likelihood of unplanned customer outages. With the increased line capacity, PSE will be able to remove an automatic tripping scheme that opens the south end of the line when system events cause the line to overload, which decreases exposure of the customers of Norlum and Alger substations to subsequent line outages, and also strengthens the transmission system between Whatcom and Skagit Counties.

Q. Describe how PSE kept management informed during Sedro #4.

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in February 2011 for the substation work to proceed to the design phase, in June 2014 for the transmission line work to proceed to the design phase, in June 2015 to update budget and again in October 2018 to update budget and scope.

Q. Were there any material changes that impacted the project scope, schedule or budget of Phases A and B? If so, describe.

A. Yes. In November 2016, Phase A and Phase B of the project was estimated at $8.8 million without AFUDC. There were two material changes during Phases A and B that increased the project cost to $10 million without AFUDC, as described below. PSE is seeking recovery of $8.1 million in this rate case, as lagging contractor invoices and control zone mitigation costs have been incurred in 2019.

- Skagit County enacted a Control Zone policy, which is intended to improve safety on county roads, and typically requires poles to be moved further away from the fog line. However, to avoid county farmland zoning restrictions, poles could not be moved out of the right of way, and PSE had to mitigate with added guardrail to meet control zone requirements. This resulted in over $450,000 in added costs.

- The project cost also increased due to various construction related issues, including poor soil conditions which added casings and anchors, additional vegetation removal and trimming, as well as added scope including additional disconnect switches and voltage regulators to improve reliability. These changes resulted in a project cost increase of approximately $750,000.

Q. Have the benefits from Sedro #4 been realized and how does PSE know this?

A. Reliability improvements have been realized for Phase A and Phase B, as these line segments have been rebuilt with new poles, wires, cross-arms and insulators which are not as susceptible to damage. During the 2018-2019 storm season, there were two storm related outages of the Sedro Woolley-Bellingham #4 transmission line, both of which saw customers restored by automatic switching prior to the line being repaired. On December 20, 2018, a tree contacted the rebuilt section of line. The upgraded infrastructure was not damaged, and the outage was restored by simply removing the tree. On January 3, 2019, a tree contacted the line in a section that had not yet been rebuilt; an aged pole was broken and required replacing, which occurred several days later. The line remained fed from only one direction until the repair was complete, which meant that the customers of the two substations were at risk of outage if another storm-related or transmission line fault had occurred prior to the repair. The full benefits of the project will be realized once the project is complete, as the entire line will be rebuilt with upgraded infrastructure and the capacity of the line will increase allowing the automatic tripping scheme, which was previously discussed, to be removed.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.