Exh. RAV-1T
Docket UE-19____
Witness: Rick A. Vail

**BEFORE THE WASHINGTON**

**UTILITIES AND TRANSPORTATION COMMISSION**

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| WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,<br><br>Complainant,<br><br>v.<br><br>PACIFICORP dba PACIFIC POWER & LIGHT COMPANY<br><br>Respondent. | Docket UE-19____ |

**PACIFICORP**

**DIRECT TESTIMONY OF RICK A. VAIL**

**December 2019**

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**Q. Please state your name, business address, and present position with PacifiCorp.**

A. My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. My present position is Vice President of Transmission. I am responsible for transmission system planning, customer generator interconnection requests and transmission service requests, regional transmission initiatives, capital budgeting for transmission, transmission and distribution project delivery, and administration of the Open Access Transmission Tariff (OATT). I am testifying for PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company).

## QUALIFICATIONS

**Q. Please describe your education and professional experience.**

A. I have a Bachelor of Science degree with Honors in Electrical Engineering with a focus in electric power systems from Portland State University. I have been Vice President of Transmission for PacifiCorp since December 2012. I was Director of Asset Management from 2007 to 2012. Before that position, I had management responsibility for a number of organizations in PacifiCorp's asset management group including capital planning, maintenance policy, maintenance planning, and investment planning since joining PacifiCorp in 2001.

## PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony in this case?**

A. The purpose of my testimony is to describe PacifiCorp's transmission system and the benefits it provides to Washington customers. PacifiCorp's transmission system is designed to reliably transfer electric energy from a broad array of generation resources to load. PacifiCorp's interconnection to other balancing authority areas (BAAs) and participation in the Energy Imbalance Market (EIM) provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, all transmission system capacity increases provide benefits to customers by increasing reliability and allowing more generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generation resources for reserve capacity to comply with mandatory reliability standards.

I also specifically describe PacifiCorp's major capital investment projects for new distribution and transmission systems included in this rate case. These investments include the transmission projects associated with Energy Vision 2020 in addition to other transmission improvements. My testimony demonstrates that the Company has made prudent decisions related to these projects and that these investments result in an immediate benefit to PacifiCorp's customers in Washington. I recommend that the Washington Utilities and Transportation Commission (Commission) find these investments prudent and in the public interest.

## OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM AND INVESTMENT DRIVERS

**Q. Please briefly describe PacifiCorp's transmission system.**

A. PacifiCorp owns and operates approximately 16,500 miles of transmission lines ranging from 46 kilovolts (kV) to 500 kV across multiple western states. PacifiCorp has nearly two million customers with approximately 137,000 customers located in Washington. PacifiCorp operates two BAAs – PacifiCorp East (PACE) BAA and PacifiCorp West (PACW) BAA. The PACW BAA includes interconnections with the Bonneville Power Administration (BPA), the northern portion of the California

Independent System Operator (CAISO), and other utilities in California, Oregon, and Washington. The PACE BAA includes interconnections with utilities in the intermountain west and southwest, which also provides access to the southern portion of the CAISO. PacifiCorp has two generation facilities that are "pseudo-tied" into the PACW BAA, but physically located in other BAAs – the Jim Bridger generation facility and the Colstrip generation facility.

**Q. What does it mean to have generation pseudo-tied into another BAA?**

A. When a generation facility is pseudo-tied to a BAA to which it is not connected, that facility will be dispatched to meet the real-time load requirements in the BAA into which it is pseudo-tied, if not previously scheduled to another BAA. A balancing authority is required under the reliability standards to balance loads and resources in real-time. This is primarily accomplished by dispatching those resources physically interconnected to the BAA that are not scheduled for export. Imported energy from generation facilities located outside the BAA generally cannot be dispatched by the balancing authority to balance its BAA in real-time. A pseudo-tie provides an alternative arrangement that allows the remote generation facility to operate as if it was interconnected to the BAA, and will then be dispatched by the balancing authority to meeting its reliability obligations. There must be sufficient transmission rights to effectuate the pseudo-tie, but for operational purposes the generation facility is considered electrically connected to the BAA into which it is pseudo-tied. This alternative allows a utility to locate and operate a generation facility located outside its BAA to meet customer needs and maintain a balanced system. This provides additional flexibility in generation resource decisions and supports the practice of resource planning on a risk-adjusted, least cost basis.

**Q. How does PacifiCorp operate the two BAAs?**

A. PacifiCorp separately balances each BAA for energy and load. To optimize dispatch for the benefit of customers, PacifiCorp dispatches generation across both BAAs to serve load across the entire system. PacifiCorp can transfer energy from PACE to PACW under transmission service agreements with Idaho Power Company (Idaho Power) and from the Jim Bridger generation facility. PacifiCorp has also obtained additional dynamic rights across the Idaho Power transmission system as part of the Idaho Power Asset Exchange, described later in my testimony. Further, PacifiCorp can transfer energy from the Jim Bridger generation facility to PACE. The flexibility of PacifiCorp's integrated transmission system provides options for optimizing dispatch to serve load and designating units for holding reserves, and provides for additional reliability during planned or unplanned generation outages. PacifiCorp also provides transmission service across both BAAs, meaning that a transmission customer can purchase transmission service from any point in one BAA to the other BAA for a single tariff rate. These benefits will be described more fully in my testimony.

**Q. Please describe PacifiCorp's responsibility for maintaining reliability on its transmission system.**

A. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888,[1]

[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

which required that transmission system owners provide non-discriminatory access to their transmission systems. PacifiCorp is obligated under its OATT to plan its transmission system for the open access of all transmission customers. Through the OATT Attachment K local planning process and the FERC Order 1000 regional and inter-regional planning processes, PacifiCorp participates in open stakeholder planning processes covering its entire transmission footprint. These planning processes result in system plans that incorporate economics, reliability, and public policy inputs and requirements. PacifiCorp must also coordinate with other entities in the region for transmission planning purposes as required under FERC Order No. 1000.[2] In addition to these more general requirements, PacifiCorp also must comply with the specific requirements of the mandatory reliability standards approved by FERC.

**Q. Who establishes transmission reliability standards?**

A. FERC directs the North American Electric Reliability Corporation (NERC) to develop Reliability Standards to ensure the safe and reliable operation of the Bulk Electric System (BES) in the United States in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards. A subset of the transmission reliability standards are the transmission planning standards (TPL Standards). The purpose of the TPL Standards is to "establish Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System

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[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), order on reh'g, Order No. 1000-B 141 FERC ¶ 61,044 (2012).

conditions and following a wide range of probable Contingencies."[3] The TPL Standards, along with regional planning criteria (*i.e.*, regional planning criteria established by the Western Electricity Coordinating Council (WECC)) and utility-specific planning criteria, define the minimum transmission system requirements to safely and reliably serve customers.

**Q. How does PacifiCorp ensure compliance with the TPL Standards?**

A. The Company plans, designs, and operates its transmission system to meet or exceed NERC Standards for BES and WECC Regional standards and criteria. To ensure compliance with applicable TPL Standards, PacifiCorp conducts an annual system assessment to evaluate the performance of the Company's transmission system and to identify system deficiencies. The annual system assessment is comprised of steady-state, stability, and short circuit analyses[4] to evaluate peak and off-peak load seasons in the near-term (one-, two-, and five-year) and long-term (10-year) planning horizons. The assessment is performed using power flow base cases maintained by WECC and developed in coordination among all transmission planning entities in the Western Interconnection. These base cases include load and resource forecasts along with planned transmission system changes for each of the future year cases and are intended to identify future system deficiencies to be mitigated.

As part of the annual system assessment, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of transmission

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[3] *See* http://www.nerc.com/files/tpl-001-4.pdf.

[4] Analyses consist of taking a normal system (N-0) and applying events (N-1, N-1-1, N-2, etc.) within each category (P0, P1, P2, P3, etc.) listed within the TPL Standards in order to identify system deficiencies. Example: An N-1-1 event describes two transmission system elements being out of service at the same time, but due to independent causes. An example of an N-1-1 event would be a planned outage of one 230 kV transmission line followed by an unplanned outage of any element in the system being used to continue service with the initial element out.

system reinforcement projects or, as applicable, adoption of new operating procedures. In certain instances, operating procedures prescribing action to change the configuration of the transmission system can prevent deficiencies from occurring when there are two back-to-back (N-1-1) (or concurrent) transmission system events. However, the use of operating procedure actions have limitations. In particular, actions taken in connection with operating procedures that are designed to protect the integrity of the larger integrated transmission system in the Western Interconnection of the United States can lead to large numbers of customers being at risk of an outage upon the occurrence of the second of two back-to-back (N-1-1) events. An effective corrective action plan is critical to ensuring system reliability so that large numbers of customers are not subjected to avoidable outage risk.

**Q. Is compliance with the reliability standards optional?**

A. No. The reliability standards are a federal requirement, subject to oversight and enforcement by WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years, and may be required to prove compliance during other NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1 million per day, per violation. Accordingly, and as described more fully later in my testimony, compliance with reliability standards is a major driver for the new capital investments in PacifiCorp's system transmission assets identified in and supported by my testimony.

**Q. Please identify other drivers that are relevant to the capital investments in PacifiCorp's distribution and transmission systems described in your testimony.**

A. There are several other drivers that inform whether PacifiCorp will build new distribution and transmission facilities, including increased demand for transmission capacity, requests for transmission service, increased demand for distribution capacity, and the age and condition of existing distribution and transmission facilities. The specific drivers for the projects addressed in my testimony are described in more detail later in my testimony.

## CUSTOMER BENEFITS OF PACIFICORP'S TRANSMISSION SYSTEM

**Q. What is PacifiCorp's proposal in this general rate case regarding cost- and benefit-allocation of the Company's transmission system?**

A. Consistent with the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) discussed in the testimony of Ms. Etta Lockey and Mr. Michael G. Wilding, PacifiCorp proposes to allocate the costs and benefits of the entirety of PacifiCorp's transmission system to Washington. This includes all transmission assets in both PACW and PACE.

**Q. Please describe how the PacifiCorp transmission system benefits Washington customers.**

A. The testimony of Mr. Wilding addresses the specific benefits of Washington's transition to system transmission under the WIJAM. My testimony addresses, at a high-level, how the benefits of access to the entirety of PacifiCorp's integrated transmission system make it used and useful for Washington customers. PacifiCorp's transmission system is designed to reliably transport electricity from a broad array of generation resources to load across both BAAs. PacifiCorp operates a geographically diverse and expansive transmission system serving retail customers in six western states. This unique geographic footprint, including over 16,500 miles of transmission lines, allows the Company to take advantage of efficiencies and economies from both a planning and operational perspective due to, among other things, retail load characteristics, and variable resource diversity. PacifiCorp's transmission system provides over 200 interconnections with adjacent transmission provider BAAs as well as access to regional energy market hubs in Washington, the California-Oregon Border, Utah, the Four Corners area, and Arizona.

PacifiCorp's geographic diversity, access to adjacent transmission providers and BAAs, and access to regional energy market hubs allows PacifiCorp to economically dispatch units across its system and transfer energy from other systems as facilitated by the Company's participation in the EIM. As the result of PacifiCorp's expansive footprint, PacifiCorp is also uniquely situated to access some of the nation's best wind and solar resources to serve load through PacifiCorp's service territory.

PacifiCorp also takes advantage of its transmission system to minimize operation costs related to generation reserve requirements and blackstart capability. PacifiCorp is required to carry reserves to ensure system reliability in the event of changes in load or system events. Instead of being required to carry reserves and blackstart capability in each individual BAA, PacifiCorp is able to operate its transmission as a collective system and use resources that are geographically remote to meet the system requirements in all areas that PacifiCorp serves. This allows the Company to engage in the most economic dispatch to lower costs for its customers.

**Q. Does PacifiCorp currently carry reserves in each BAA sufficient to meet that BAA's requirements?**

A. Not always. PacifiCorp often meets its reserve requirements in PACW with resources located in PACE.[5] While meeting the reserve requirements in the reliability standards is not a transmission function, PacifiCorp's transmission system provides flexibility for PacifiCorp to meet its reserve requirements.

**Q. Are investments across the system necessary to maintain PacifiCorp's transmission system?**

A. Yes. The ability to flexibly use a diverse set of energy resources is significantly dependent on the strength and reliability of PacifiCorp's transmission system connecting those resources to the PacifiCorp retail customers in all six states. Transmission system outages and other real-time operation constraints place additional burden on the remainder of the transmission system as corrective actions plans are implemented to maintain compliance with NERC and WECC standards and guidelines and ensure the reliability of service to all PacifiCorp customers.

**Q. Can the benefits of a reliable system be easily quantified?**

A. No. Reliability is, essentially, the absence of a system disruption. Other than the impact on net power costs, which are discussed in the testimony of Mr. Wilding, it is very difficult to quantify the benefit of reliability investments. That being said, the

[5] *See* Exhibit No. MGW-1CT.

access to different regions and redundancy in operations provides reliable service under a variety of conditions that benefits all PacifiCorp's customers.

**Q. Will PacifiCorp's Washington customers benefit from PacifiCorp's investments in the PACE BAA?**

A. Yes. As I mentioned before, Washington customers will have access to some of the best wind resources in the nation located in Wyoming. Washington will also have access to solar resources in Utah and the desert southwest. Additionally, dispatch benefits from the EIM will include access to southern California. PacifiCorp's entire transmission system facilitates these benefits.

## IDAHO POWER ASSET EXCHANGE

**Q. Please provide a description of the Idaho Power/PacifiCorp Asset Exchange.**

A. The Idaho Power Asset Exchange included the purchase of transmission line and substation assets by PacifiCorp from Idaho Power and the sale of like-kind assets by PacifiCorp to Idaho Power. As a result of the Idaho Power Asset Exchange, PacifiCorp traded like-kind transmission facilities of nearly equal net book value with Idaho Power. The legacy agreements provided PacifiCorp 1,600 megawatts (MW) of total transmission capacity, including 200 MW of dynamic transfer capability. The Idaho Power Asset Exchange increased PacifiCorp's dynamic transfer capability to 400 MW. The Idaho Power Asset Exchange also provided increased reliability and flexibility. Please refer to Exhibit No. RAV-2 for maps showing PacifiCorp's rights and assets before and after the transaction.

**Q. Please describe the need for the purchase and sale agreement.**

A. PacifiCorp and Idaho Power operate and maintain respective ownership of certain jointly-owned facilities as well as independently-owned transmission facilities in Idaho, Oregon, Washington, and Wyoming. The operation and ownership of many of these facilities was governed under a complicated collection of legacy agreements, including a 1969 Jim Bridger Ownership Agreement titled the Restated Transmission Service Agreement and a 1969 Jim Bridger Operation Agreement titled the Restated and Amended Transmission Facilities Agreement. Some of the legacy agreements had been in place for over 40 years.

In the years following the establishment of such legacy agreements, changes had occurred for both PacifiCorp and Idaho Power rendering the legacy agreements ineffective and ill-suited over time to optimize existing transmission facilities and effectively respond to regulatory changes, load growth, investment in system upgrades, and reliability and operational needs. The complexity of these legacy agreements resulted in disputes over the years between the parties regarding contract interpretation. In addition, the transmission systems of both parties continue to evolve and there was no effective mechanism under the legacy agreements to account for evolving operational procedures and changes in regulatory requirements. By better aligning resources and establishing more modernized agreements to govern ownership and the operation and maintenance of the associated transmission facilities, this transaction benefitted both parties, putting them in a position to better provide reliable and efficient transmission service for customers now and into the future.

An example of a system change that was not supported by the legacy agreements was the completion of the Populus substation in southern Idaho, which provided the ability to move resources from Wyoming to Utah, coupled with the Gateway Central project, which provided the ability to move resources from Utah into Oregon and Washington. These types of service were not contemplated in the legacy agreement. The asset exchange provided for system flexibility to use the least-cost resources to service load across PacifiCorp's system and utilize renewable resources remote from load to meet current and future renewable portfolio standard needs.

**Q. Were there other benefits with the new agreement and what was the value of the agreement?**

A. Yes. The Idaho Power Asset Exchange enhanced the Company's ability to serve load under certain outage conditions. Before the exchange PacifiCorp was required to request additional tariff service from Idaho Power, if available, to move resources west of Jim Bridger to serve loads in Idaho, Oregon, and Washington. With the purchase and sale agreement PacifiCorp gained ownership of new transmission assets that eliminated this issue. Also under the purchase and sale agreement PacifiCorp gained 200 MW of dynamic scheduling rights between Utah/Wyoming and Oregon/Washington. Incremental transmission capacity supports the operation of the EIM, which relies on available transmission capacity. Furthermore, the additional capacity from the Idaho Power Asset Exchange enhanced the ability to move renewable resources across the system from Wyoming and Utah to service loads in Washington and Oregon.

**Q. Was the Idaho Power Asset Exchange previously approved by the Commission?**

A. Yes. The Commission approved the Company's petition for authorization to exchange certain assets with Idaho Power on September 24, 2015, in Docket UE-144136, Order 01.[6]

**Q. Has the Commission allowed all of the exchanged assets to be included in rates?**

A. Not yet. In the Company's 2015 limited-issue rate case, Docket UE-152253 (2015 Rate Case), Order 12, the Commission rejected PacifiCorp's proposed inclusion of the exchange assets in rates because the Company had not "calculated the quantifiable benefits of the exchange or provided for their inclusion in the power cost baseline, nor is it proposing to reflect power costs savings resulting from the additional 200 MW of dynamic transfer capability."[7] The Commission, however, stated that should PacifiCorp propose to include the benefits of these assets in the power cost baseline of its Power Cost Adjustment Mechanism, it would consider inclusion of the costs associated with these assets at that time.[8]

**Q. Is PacifiCorp proposing to include the benefits of these assets in its power cost baseline in this case?**

A. Yes. Mr. Wilding discusses the overall benefits to net power costs associated with access to PacifiCorp's non-emitting resources located across both of PacifiCorp's BAAs.[9] With the additional evidence of customer benefit, PacifiCorp proposes that the Commission now include the Idaho Power Asset Exchange assets in Washington

[6] *In the matter of Pac. Power & Light Co.*, Docket No. UE-144136, Order 01 at p. 4, ¶ 15 (September 24, 2015).
[7] *WUTC v. Pac. Power & Light Co.*, Docket No. UE-152253, Order 12 at p. 72, ¶ 216 (September 1, 2016).
[8] *Id.* at p. 72, ¶ 216.
[9] *See* Exhibit No. MGW-1CT.

rates as part of the transition to a full system allocation of PacifiCorp's transmission system costs.

## OVERVIEW OF INVESTMENTS DESCRIBED IN TESTIMONY

**Q.** **What specific distribution and transmission system investments are you addressing in your testimony?**

A. My testimony addresses PacifiCorp's major new distribution and transmission system projects included in this general rate case filing. Specifically, my testimony addresses the following projects:

**1. Aeolus to Bridger/Anticline 500 kV Transmission Project:**

The Aeolus to Bridger/Anticline 500 kV Transmission Project includes the construction of facilities to integrate approximately 1,150 MW of new wind generation resources located in southeast Wyoming (*i.e.*, TB Flats I and II, Cedar Springs, and Ekola Flats, collectively referred to as the Energy Vision 2020 Wind Projects or individually referred to as an Energy Vision 2020 Wind Project)[10] and deliver energy from those resources across PacifiCorp's system. Those facilities include:

- A 140-mile, 500 kV transmission line (Aeolus-to-Anticline line), which includes construction of the new Aeolus (500/230 kV) and Anticline (500/345 kV) substations; a map of the proposed line can be found attached in Exhibit No. RAV-3;
- A five-mile, 345 kV transmission line that will extend from the proposed Anticline substation to the Jim Bridger substation, along with

[10] The Energy Vision 2020 Wind Projects are more thoroughly discussed in the testimony of Mr. Chad A. Teply.

associated interconnection facilities at the Jim Bridger substation to accommodate the interconnection of the 345 kV line from the proposed Anticline substation; and

- A voltage control device at the existing Latham substation.

Additional network upgrades are also required to accommodate the Aeolus to Bridger/Anticline 500 kV Line Project and the interconnection of the Energy Vision 2020 Wind Projects (230 kV Network Upgrades). These network upgrades include:

- A new 16-mile 230 kV transmission line parallel to an existing 230 kV line from the Shirley Basin substation to the proposed Aeolus substation, including modifications to the Shirley Basin substation to accommodate the new line;
- The reconstruction of four miles of an existing 230 kV transmission line between the proposed Aeolus substation and the Freezeout substation, including modifications of the Freezeout substation to accommodate the new line; and
- The reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, including modifications to the Freezeout and Standpipe substations to accommodate the transmission lines.

The reconstructed sections are proposed to be in a parallel alignment to the existing 230 kV transmission lines. The Aeolus to Bridger/Anticline 500 kV Transmission Project and 230 kV Network Upgrades are needed to support interconnection of the new Energy Vision 2020 Wind Projects, which are described in the testimony of Mr. Chad A. Teply.

**2. Wallula to McNary 230 kV Transmission Line:**

The Wallula to McNary 230 kV new transmission line extending from Wallula substation located in Wallula, Washington, to McNary substation located near Umatilla, Oregon, as shown in the map attached in Exhibit No. RAV-4.

**3. Snow Goose 500/230 kV Substation:**

The Snow Goose 500/230 kV substation which is located near Klamath Falls, Oregon, as shown in the map attached in Exhibit No. RAV-5.

**4. Vantage to Pomona Heights 230 kV Transmission Line:**

The Vantage to Pomona Heights 230 kV new transmission line extending from Vantage substation located northeast of Yakima, Washington, to Pomona Heights substation located in Selah, Washington, as shown in the map attached in Exhibit No. RAV-6.

**5. Goshen-Sugarmill-Rigby 161 kV Transmission Line:**

The Goshen-Sugarmill-Rigby 161 kV transmission line rebuild of an existing 69 kV line from Goshen substation to Sugarmill substation and then construction of a new 161 kV line from Sugarmill substation to Rigby substation located in the southeast Idaho area, as shown in the map attached in Exhibit No. RAV-7.

**6. Gromore Substation:**

The Gromore Substation - Construct New 115 kV-12 kV substation located in Yakima, Washington, as shown on the map attached in Exhibit No. RAV-8.

**7. Stadelman Fruit Project:**

The Stadelman Fruit project increased 115-12.47 kV transformer capacity at Punkin Center substation by 25 megavolt amperes (MVA) and built a new distribution feeder to facilitate load transfer relief at Toppenish substation and its Zillah feeder in Yakima, Washington, as shown on the map attached in Exhibit No. RAV-9.

**Q. What are the projected costs associated with these distribution and transmission investments and their associated in-service dates?**

A. Table 1 identifies the specific projects and associated costs and in-service dates.

| Table 1 | | |
|---|---|---|
| **Project** | **Total Company Cost ($m)** | **In-Service Date** |
| Aeolus to Bridger/Anticline 500 kV line[11] | | |
| Sequence Two (In-Service) | $4.1 | July 2018 |
| Sequence Three | $11.1 | December 2019 |
| Sequence Four | $663.9 | December 2020 |
| Q707 TB Flats 1 | $30.6 | December 2020 |
| Q712 Cedar Springs Wind 1 | $61.7 | December 2020 |
| Wallula to McNary 230 kV New Transmission Line | | |
| Sequence One (In Service) | $6.4 | December 2017 |
| Sequence Two (In Service) | $36.2 | January 2019 |
| Snow Goose 500-230 kV New Substation Project | | |
| Sequence One (In Service) | $10.3 | May 2017 |
| Sequence Two (In Service) | $32.5 | November 2017 |
| Vantage to Pomona Heights 230 kV New Transmission Line Project | $57.3 | May 2020 |
| Goshen-Sugarmill-Rigby 161kV Transmission Line Project | | |
| Sequence One | $21.5 | November 2020 |
| Sequence Two (not included in this case) | N/A | November 2022 |
| Gromore Sub-Construct New 115kV-12kV Sub (In Service) | $7.6 | April 2018 |
| Stadelman Fruit, Yakima WA. 5Y245 | | |
| Sequence One (In Service) | $5.6 | June 2016 |
| Sequence Two (In Service) | $1.2 | January 2017 |

These amounts include costs associated with engineering, project management, materials and equipment, construction, right-of-way (including rights acquired by condemnation), and an allowance for funds used during construction. These costs are also shown in the testimony and exhibits of Ms. Shelley E. McCoy. The in-service dates are based on the best available information at the time of

[11] As discussed later in my testimony, Sequence One was placed into service in 2011.

preparing this case. PacifiCorp will include any changes to these assumptions when it updates the forecast for capital additions in rebuttal.

**Q. Please briefly describe the benefits associated with these investments.**

A. The benefits associated with these investments include increased load serving capability, enhanced reliability, conformance with NERC Reliability Standards, improved transfer capability within the existing system, relief of existing congestion, and interconnection and integration of new wind resources into PacifiCorp's transmission system. These benefits will be described more fully below.

**Q. Will PacifiCorp's OATT transmission customers pay for some of these assets?**

A. Yes, through OATT transmission charges. The Company's current transmission formula rate (included in PacifiCorp's OATT) was approved by FERC in Docket No. ER11-3643.[12] The Company's transmission formula rate is updated annually with the annual transmission revenue requirement (ATRR) that represents the annual total cost of providing firm transmission service over the test year. The ATRR calculation incorporates all transmission system investments by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments. Transmission assets, including new transmission capital, are included in the ATRR, weighted by months in service. The ATRR is converted into a rate by dividing the ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary services) are included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions.

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[12] *In re PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

**Q. Please explain how network upgrade cost allocation works under the OATT.**

A. In accordance with its OATT, when PacifiCorp receives a request for generation interconnection or transmission service, the Company completes studies to determine what new facilities or upgrades to existing facilities are required to accommodate the request. The studies identify the facilities and upgrades required and classify the asset additions required to support the service into two categories: direct assigned or network upgrade. Direct assigned assets are those assets that only benefit or are used solely by the customer requesting generator interconnection or transmission service. Those costs are directly assigned and paid for by that customer and will not be included in either the Company's ATRR or retail rate base. Network upgrades, on the other hand, are those assets that benefit all customers using the transmission system. Costs associated with network upgrades are investments by the transmission provider and are included in PacifiCorp's ATRR[13] and retail rate base.

## AEOLUS TO BRIDGER/ANTICLINE 500 KV TRANSMISSION PROJECT

**Q. Please describe the investment for the Aeolus to Bridger/Anticline 500 kV Transmission Project.**

A. The Aeolus to Bridger/Anticline 500 kV Transmission Project is planned to be placed in service in four sequences. The first sequence was the purchase of property used for the new Aeolus and Anticline substations, which were placed in service in March 2011. The second sequence was to construct a replacement access bridge over the

[13] For generation interconnection customers, those customers may be required to pay the initial cost of network upgrades, subject to refund through credits to invoiced charges for transmission service and full refund of any remaining amounts after 20 years. *See* Section 11.4 of PacifiCorp's Standard Large Generator Interconnection Agreement (OATT Attachment N, Appendix 6 and available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20190601_OATTMASTER.pdf); *see also* Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-B, 109 FERC ¶ 61,287 (December 20, 2004).

Medicine Bow River and complete associated upgrades to an existing unpaved county road for $4.1 million in July 2018. The third sequence of work planned in December 2019, for an estimated $11.1 million, is the installation of a Static Synchronous Compensator (STATCOM) voltage control device. To accommodate this equipment, the Latham Substation will be expanded with a new line termination bay. Finally, the last sequence of plant in service is the two 500 kV substations as well as the transmission line for $663.9 million in December 2020.

**Q. Please describe the 230 kV Network Upgrades.**

A. There are four generation interconnection projects selected as part of a request for proposal to interconnect 1,150 MW of new wind generation to the 230 kV transmission system in eastern Wyoming. The request for proposal process and the resulting resources selected are described in the testimony of Mr. Rick T. Link. A separate generation interconnection agreement was negotiated and signed for each of the four projects.

Q707 TB Flats 1 is planned to be placed in service in December 2020 and requires $30.6 million of network upgrades. This project includes a new 16-mile 230 kV transmission line parallel to an existing 230 kV line from Shirley Basin substation to the proposed Aeolus substation, including modifications to the existing Shirley Basin substation.

Q712 Cedar Springs Wind 1 is planned to go into service in December 2020 and requires $61.7 million of network upgrades. This project includes the reconstruction of four miles of an existing 230 kV transmission line between the proposed Aeolus substation and the Freezeout substation, including modifications as required at the Freezeout substation; the reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation including modifications as required at the Freezeout and Standpipe substations; and the reconstruction of 16 miles of an existing 230 kV transmission line from the proposed Aeolus substation to the existing Shirley Basin substation.

**Q. Please explain why this investment in the Aeolus to Bridger/Anticline 500kV Transmission Project was needed.**

A. As described in more detail in the testimony of Mr. Link, the Aeolus to Bridger/Anticline 500 kV Transmission Project supports the Company's short- and long-term energy demands for serving customers across the entire PacifiCorp system, and will strengthen the overall reliability of the existing Wyoming transmission system and therefore PacifiCorp's entire transmission system.

The Aeolus to Bridger/Anticline 500 kV Transmission Project has long been recognized as an integral component of PacifiCorp's long-term transmission planning, but the construction of the project has not been economic until now. The renewal of the federal wind production tax credits (PTCs) created a unique opportunity for the Company to acquire significant cost-effective, zero emission wind resources, generating PTCs that provide cost savings necessary to economically construct the project. To achieve the full customer benefits of the PTCs, however, the Company must develop the Energy Vision 2020 Wind Projects and the Aeolus to Bridger/Anticline 500 kV Transmission Project together and bring them into service by December 31, 2020.

**Q. Can PacifiCorp develop the Energy Vision 2020 Wind Projects without the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. No. The Energy Vision 2020 Wind Projects are not economic without the completion of the Aeolus to Bridger/Anticline 500 kV Transmission Project, which is needed to relieve existing congestion and to interconnect and integrate new PTC-eligible wind resources in high-wind areas of Wyoming. Similarly, the Aeolus to Bridger/Anticline 500 kV Transmission Project is not economic to PacifiCorp customers if there are no incremental cost-effective wind resources producing PTCs.

**Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project benefit customers and improve system performance?**

A. The Aeolus to Bridger/Anticline 500 kV Transmission Project will: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection and integration of new generation resources and more efficient dispatch of and greater flexibility managing existing resources; (2) provide critical voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses. Remarkably, customers will be able to receive all of these benefits, while taking advantage of the PTCs from the Energy Vision 2020 Wind Projects to offset the costs of the project.

**Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project increase transmission capacity in southeastern Wyoming?**

A. Currently, the Company's transmission system in southeastern Wyoming is operating at capacity, which limits transfer of existing resources from eastern Wyoming and precludes the ability to interconnect and integrate additional resources east of

Bridger/Anticline. This investment will increase the transfer capability from east to west across Wyoming by 951 MW. When the Aeolus to Bridger/Anticline 500 kV Transmission Project is complete, the Company estimates that it will be able to accommodate up to approximately 1,510 MW of additional new wind resources east of the Bridger/Anticline substation.

The increased transmission capacity also provides improved access to existing generation resources, and will provide options to access other resources, including renewable resources. The resulting increase in capacity allows flexibility to use future generation and interconnected transmission facilities.

**Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project impact the dispatch of the Company's existing generation resources?**

A. The Aeolus to Bridger/Anticline 500 kV Transmission Project will increase the ability to dispatch the Company's existing resources. With the project being constructed between eastern Wyoming and Jim Bridger/Anticline, eastern Wyoming transmission congestion will be mitigated and wind resources entering the Jim Bridger energy hub can flow onto the Bridger West transmission path to PacifiCorp load centers. With increased wind generation entering the Jim Bridger energy hub, Jim Bridger generating plant can be dispatched to maximize wind transfers out of the energy hub.

**Q. Will the increased capacity benefit customers in any other ways?**

A Yes. To provide low-cost energy, the Company must have the ability to acquire power from numerous generation sources and negotiate the most competitive pricing. By adding transmission capacity, the Company has increased its ability and options to obtain additional generation sources at competitive pricing. The Aeolus to Bridger/Anticline 500 kV Transmission Project will result in a stronger transmission system in southern Wyoming and therefore throughout PacifiCorp's entire service territory.

**Q. Is the increased capacity provided by the Aeolus to Bridger/Anticline 500 kV Transmission Project consistent with the Company's obligation to provide transmission service under its OATT?**

A. Yes. The Company's OATT, approved by FERC, details the Company's requirements and obligations to provide transmission service. Section 28.2 of the OATT defines the Company's responsibilities, which include the requirement to "plan, construct, operate, and maintain the system in accordance with good utility practice." Section 28.3 states the requirement for the Company to provide "firm service over the system so that designated resources can be delivered to designated loads." The Company is required to provide adequate and non-discriminatory service to all network customers. Although the Aeolus to Bridger/Anticline 500 kV Transmission Project is not specifically mandated by the Company's obligations under its OATT, the project will allow the Company to more efficiently meet current and forecasted customer energy demand by relieving the existing transmission congestion in southeastern Wyoming.

**Q. What are the benefits resulting from the critical voltage support that will be provided by the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. Under certain operating conditions, voltage control issues have limited the ability to add additional resources, particularly wind resources, in southeastern Wyoming.

The Aeolus to Bridger/Anticline 500 kV Transmission Project will greatly enhance the ability to control voltage issues and allow additional wind generation to be integrated into the Company's system.

**Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project improve system reliability?**

A. The transmission grid can be affected in its entirety by what happens on an individual transmission line or path. For example, the transmission system between eastern and central Wyoming is comprised of several individual transmission lines or line segments. A single outage on any of the individual lines or line segments due to storm, fire, or other external human interference can and does cause significant reductions in transfer capability, which can negatively impact the Company's ability to serve customers. Line outages require the Company to curtail generation resources to stabilize system voltages and require less efficient re-dispatch of system resources to meet network load requirements. This in turn places a burden across the entire interconnected system as generation resources across PacifiCorp's service territory, using PacifiCorp's transmission system, are used to ensure the continued reliability of energy supply to all PacifiCorp customers.

In the event of a line outage, the redundancy provided by the Aeolus to Bridger/Anticline 500 kV Transmission Project will allow the Company to continue to meet native load service obligations and other contractual obligations to third parties. Strengthening this path and increasing system redundancy will benefit all customers by reducing the risk of outages and inefficient dispatch resulting from those outages.

In addition, the Aeolus to Bridger/Anticline 500 kV Transmission Project will improve the Company's ability to perform required maintenance without significant operational impacts to the system, and will reduce impacts to customers during planned and forced system outages. Transmission line and substation maintenance windows are currently limited because the system is highly utilized. By relieving congestion and providing additional transmission paths, this investment will allow greater flexibility to the Company in the operation of its transmission system.

**Q. Can you provide an example where the Aeolus to Bridger/Anticline 500 kV Transmission Project would have mitigated the impact of an outage on the 230 kV transmission system?**

A. Yes. For an outage of the Latham – Point of Rocks 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates the overload on the Dave Johnston – Amasa 230 kV line. For an outage of the Mustang – Spence 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates the overload on 230 kV lines west of Platte. For an outage of the Riverton – Wyopo 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates overloads on 230 kV lines west of Platte. For an outage of the Dave Johnston to Amasa 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project eliminates the overload on the 230 kV lines west of Platte. For an outage of the Platte to Standpipe 230 kV line, the Aeolus to Bridger/Anticline 500 kV Transmission Project will eliminate the need to trip approximately 130 MW of wind generation at Foote Creek.

**Q. Will the Aeolus to Bridger/Anticline 500 kV Transmission Project also enhance the Company's ability to meet the reliability standards applicable to its transmission system?**

A. Yes. Although the Company currently meets or exceeds the applicable reliability standards and criteria, the addition of the Aeolus to Bridger/Anticline 500 kV Transmission Project will allow the Company to do this more efficiently.

**Q. How do NERC and WECC standards and criteria influence the need for the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. The mandatory standards, particularly NERC's TPL-001-4 standard, require the Company to have a forward-looking transmission plan of action to reliably serve current and anticipated customer demands under certain planning horizon conditions, including normal system operations (all system elements in service) and during system contingencies (where elements of the transmission system are out of service), both planned or otherwise.

As described earlier in my testimony, the Company performs annual reliability assessments to determine that its transmission system complies with minimum mandatory system performance standards, which require that during loss of any single transmission system element (N-1 single contingencies) that firm service is maintained, no system overloads exist, and there is no loss of customer demand.

The Aeolus to Bridger/Anticline 500 kV Transmission Project is sub-segment D.2 of Gateway West, which, as part of Energy Gateway, has been included in the Company's annual TPL-001-4 assessment as part of its short- and long-term plans to dependably meet NERC and WECC reliability requirements. The Aeolus to

Bridger/Anticline 500 kV Transmission Project's new transmission segments are particularly effective in increasing system reliability under the various multiple contingency categories of the TPL-001-4 standard.

The NERC Standard TPL-001-4 has category P6 (N-1-1) that results in outage of multiple transmission elements. This category outage allows adjustment of the transmission system after the first outage following which the second outage is conducted. The Aeolus – Anticline 500 kV line will significantly help under these N-1-1 conditions. For example, the N-1-1 outage of Riverton – Wyopo 230 kV line followed with an outage of Spence – Mustang 230 kV line without the 500 kV line would require curtailment of the TOT4A path by approximately 500 MW. But with the addition of the 500 kV line this curtailment would not be required. The study was performed with TOT4A flows at 1,030 MW in the original case. The addition of the 500 kV line prevents thermal overload on the 230 kV transmission system west of Platte.

**Q. Has the Aeolus to Bridger/Anticline 500 kV Transmission Project been included in WECC path rating studies?**

A. Yes. The Aeolus to Bridger/Anticline 500 kV Transmission Project has undergone WECC's Three Phase Ratings Process, and has been approved by WECC for Phase 3-"Construction Phase" status as part of the overall Energy Gateway project. The Aeolus West transmission path and three other Gateway West transmission paths (TOT 4A, Bridger/Anticline West and Path C) have completed the Three Phase Rating Process and were granted Phase 3 status on January 5, 2011.

**Q. What is WECC's Three Phase Ratings Process?**

A. The purpose of the Three Phase Rating Process is to provide a formal process for project sponsors to attain an accepted rating and demonstrate how their Project will meet NERC Reliability Standards. The Three Phase Rating Process addresses planned new facility additions and upgrades, or the re-rating of existing transmission facilities. It requires coordination through a review group comprised of the project sponsors and representatives of other systems that may be affected by the project. An accepted rating affords the project sponsor some protection against erosion of established capacity of the rated transmission facility when further expansion of the western interconnected transmission system is proposed or new limitations are discovered.

**Q. Why is WECC's Three Phase Ratings Process important to the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. This WECC approval is necessary because it allows the Company to interconnect the Aeolus to Bridger/Anticline 500 kV Transmission Project to the wider transmission system in the area and to reliably operate the new line at its approved ratings. The Aeolus to Bridger/Anticline 500 kV Transmission Project, especially when complemented with other Energy Gateway projects (specifically Aeolus to Clover, included in the 2019 Integrated Resource Plan (IRP) preferred portfolio, and Anticline to Populus and Oquirrh to Terminal, included in the PacifiCorp's IRPs over the last several cycles), will greatly strengthen the Company's transmission capacity and flexibility. The Aeolus to Bridger/Anticline 500 kV Transmission Project is regarded as a necessary interconnection point to support the long-term transmission expansion planning established in the WECC Region plans and in the most recent Northern Tier Transmission Group sub-regional plan.[14]

While the Aeolus to Bridger/Anticline 500 kV Transmission Project provides the next necessary increment of transmission capacity in the area, it also supports and complements other future transmission investments that are currently proposed by the Company as included in the 2019 IRP preferred portfolio, provides recognition for continued permitting and supports the reliability of other utilities in the region as shown in the NTTG regional plans. The construction of this line, as an integral component of the larger Energy Gateway project, positions the Company to be strongly interconnected to other regional projects currently being planned and provides options for access to additional resources.

**Q. What are the impacts to the system and the Company if the Aeolus to Bridger/Anticline 500 kV Transmission Project is not completed or delayed?**

A. If the Aeolus to Bridger/Anticline 500 kV Transmission Project is not completed, the existing congestion will remain and the Company's ability to deliver resources to load will also remain constrained. As discussed above, the Company currently meets all applicable system reliability and performance criteria and therefore the Aeolus to Bridger/Anticline 500 kV Transmission Project is not strictly required to satisfy those

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[14] PacifiCorp participates in FERC Order 1000 regional planning through membership in the Northern Tier Transmission Group. Under FERC Order 1000, regional planning groups were established to facilitate coordinated and transparent transmission system planning among the participating member entities to ensure regional transmission stability and efficiency. Currently, there are four sub-regions in the Western Interconnection of the United States, including Northern Tier Transmission Group, ColumbiaGrid, WestConnect, and California ISO. These four sub-regions each develop independent regional plans and then coordinate on interregional planning across the Western Interconnection. Effective January 2020, Northern Tier Transmission Group and ColumbiaGrid will merge into the new NorthernGrid regional planning group, of which PacifiCorp will be a participating member. Further information on NTTG is available at: http://nttg.biz/site/index.php?option=com_docman&task=cat_view&gid=308&Itemid=31.

standards. Rather, this project has long been identified as an important addition to the Company's transmission system, and the PTCs generated by the incremental wind resources provide a time-limited opportunity to build the Aeolus to Bridger/Anticline 500 kV Transmission Project now with only a moderate rate impact.

**Q. How will the Aeolus to Bridger/Anticline 500 kV Transmission Project reduce energy and capacity losses?**

A. Reduced energy and capacity losses on the transmission system have the potential to provide monetary savings over time. The addition of a new transmission line operated in parallel with existing lines reduces the electrical impedance of the transmission system, resulting in lower energy line losses (megawatt-hours) over the life of the project. Depending on the amount of power flow, line loss savings can be substantial.

**Q. Did the Company consider alternatives to the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. Yes. While long-term alternatives to constructing a new transmission line are limited, the Company did consider other approaches, but none were cost-effective. As described more fully in the testimony of Mr. Link, the Aeolus to Bridger/Anticline 500 kV Transmission Project and Energy Vision 2020 Wind Projects were included in the Company's 2017 IRP, where they were analyzed in comparison to alternatives. The resource portfolio that included the Aeolus to Bridger/Anticline 500 kV Transmission Project and Energy Vision 2020 Wind Projects was consistently the risk-adjusted, least-cost option.

The Company also considered the ability to obtain additional transmission capacity by upgrading the existing transmission system or implementing alternative transmission technologies. Indeed, since 2013 the Company has completed several important projects to enhance the transmission system in southeast Wyoming, including the dynamic line rating of the Miners (Standpipe) – Platte 230 kV line in 2013, Southern Wyoming Voltage Control Scheme, which coordinated wind generation reactive output to stabilize local area voltages, in 2015, and construction of the Standpipe substation and (60 MVAr) synchronous condenser for voltage control in 2016. These projects allowed the Company to delay the Aeolus to Bridger/Anticline 500 kV Transmission Project until 2020, but were not a long-term substitute for the project.

**Q. Is the Company confident that it can manage the construction schedule risk and deliver the Aeolus to Bridger/Anticline 500 kV Transmission Project by 2020?**

A. Yes. To manage construction schedule risk, the Company is structuring and managing the project on a firm, date-certain, fixed-price, turnkey contract basis. Construction contractors and equipment suppliers will be held to key construction and delivery milestones and development of compressed schedule mitigation plans, if required. The Company also established construction contract completion dates and backstopped them with guarantees.

**Q. Has the Company obtained all of the necessary permits and rights of way for the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. Yes.

**Q. Has the Company made substantial progress on construction of the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. Yes. The Company has placed all contracts for construction of the Aeolus to Bridger/Anticline 500 kV Transmission Project. Construction work commenced in April 2019. As of early October 2019, the 500 kV transmission line had 52 percent of structures erected and wire stringing operations has commenced. The Aeolus, Anticline, and Jim Bridger substations are under construction with grading complete and foundations as well as underground construction ongoing. Steel erection has commenced at Anticline and Jim Bridger substations. Major substation equipment is being manufactured and tested; first deliveries of circuit breakers have been received at Aeolus and Jim Bridger substations, reactive devices are in transit for an expected delivery in December 2019, and the transformers will begin arriving in spring 2020. The Latham substation expansion is now substantially complete and will be placed in service in December 2019. The voltage control device foundations and building enclosure are under construction with major equipment being manufactured and tested. Work at the Freezeout substation is complete, and the majority of the construction of the Shirley Basin substation to support the future 230 kV Transmission has been completed with the remaining work scheduled to be completed in for spring of 2020.

**Q. What are the major milestones remaining before the December 2020 in-service date for the Aeolus to Bridger/Anticline 500 kV Transmission Project?**

A. Major Milestones are identified below:

**500 kV Transmission**

- Mechanical Completion August 31, 2020
- Substantial Completion October 31, 2020

**500 kV Substations**

- Mechanical Completion Aeolus 230 kV yard; May 15, 2020
- Substantial Completion Aeolus 230 kV yard; June 15, 2020
- Mechanical Completion (all remaining work); August 31, 2020
- Substantial Completion (all remaining work); October 31, 2020

**230 kV Network Upgrades**

- Aeolus – Shirley Basin; Substantial Completion May 15, 2020
- Aeolus – Freezeout; Substantial Completion May 30, 2020
- Freezeout – Standpipe; Substantial Completion September 15, 2020
- Aeolus – Shirley Basin (rebuild); Substantial Completion September 30, 2020

**Q. Are the transmission projects currently on budget and are they forecasted to be delivered on budget?**

A. Yes.

**Q. Please describe the estimated total cost of the Transmission Project.**

A. The Aeolus to Bridger/Anticline transmission line and associated substations are estimated to cost $679.2 million, as summarized in Table 2 below.

| Table 2 | |
|---|---|
| **Item** | **Value** |
| Transmission Line | $234.6M |
| Substations | $214.1M |
| Engineering | $18.9M |
| ROW Acquisition | $16.0M |
| PM/Environmental/Support Works | $92.4M |
| In-directs | $86.7M |
| Contingency | $16.5M |
| **TOTAL** | **$679.2M** |

The entire cost of the Aeolus to Bridger/Anticline project will be paid by the Company without contribution from any transmission customer projects.

The 230 kV transmission line and associated substations are estimated to cost $92.2 million, as summarized in Table 3 below.

| Table 3 | |
|---|---|
| **Item** | **Value** |
| Transmission Line | $53.15M |
| Substations | $12.67M |
| Engineering | $3.7M |
| ROW Acquisition | $1.06M |
| PM/Environmental/Support Works | $9.15M |
| In-directs | 9.69M |
| Contingency | $2.78M |
| **TOTAL** | **$92.2M** |

The Company expects that transmission customers will contribute to the cost of the 230 kV transmission interconnections. The 230 kV transmission facilities identified to integrate the Aeolus to Bridger/Anticline single-circuit 500 kV line with the existing Wyoming transmission system are considered network upgrades.

**Q. If the Aeolus to Bridger/Anticline 500 kV Transmission Project is not fully in-service by December 31, 2020, can the Energy Vision 2020 Wind Projects still qualify for PTCs?**

A. Yes. Assuming the Aeolus to Bridger/Anticline 500 kV Transmission Project is not completed by December 31, 2020, but otherwise has facilitated synchronization to the transmission grid and commissioning of individual wind turbines in accordance with Internal Revenue Service guidance, the Company would treat a completed and functional wind turbine as being placed in service regardless of any transmission constraints affecting a wind project.

**Q. How will the costs of the Aeolus to Bridger/Anticline 500 kV Transmission Project flow into the Company's transmission rates, and who will pay these rates?**

A. Transmission assets, including new transmission capital like the Aeolus to Bridger/Anticline 500 kV Transmission Project, are included in the ATRR, weighted by months in service. The ATRR is converted into a rate by dividing ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary services) are included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions.

## WALLULA-MCNARY 230 KV NEW TRANSMISSION LINE

**Q. Please describe the investment for the Wallula to McNary 230 kV New Transmission Line.**

A. The in-service Wallula to McNary 230 kV New Transmission Line project consisted of two sequences of work, the combined costs of which are included in this general rate case filing. The first work sequence was placed in service in December 2017 for $6.4 million and included expansion at PacifiCorp's Wallula substation as well as relay and communications work at the Nine Mile substation. The second sequence of work was the construction of the new 230 kV transmission line that went into service in January 2019, for $36.2 million. A one-line diagram of the Wallula to McNary 230 kV New Transmission Line project is included in Exhibit No. RAV-4.

**Q. Please explain why this investment in the Wallula to McNary 230 kV New Transmission Line was needed and beneficial.**

A. The Wallula to McNary 230 kV New Transmission Line project was needed to enable PacifiCorp to comply with PacifiCorp's OATT, its transmission service agreements, and FERC's requirements to provide the requested transmission service. Before this line went into service, there were only two MW of available transfer capacity on the existing line between Wallula and McNary, which was insufficient to satisfy the requests for service from providers of generation capacity from renewable resources. This completion of the project now enables PacifiCorp to fulfill such requests in compliance with its OATT requirements, and will also increase the Company's access to generation capacity from renewable resources.

In addition, the project enhances transmission reliability by providing a second connection between BPA's McNary substation and PacifiCorp's Wallula substation. With only a single line between Wallula and McNary, line outages, either planned or unplanned, cause disruption of service to customers. This disruption can result in loss of service under existing contracts or reduced reliability for customers served from the Wallula substation. This new second line will provide service reliability in a single line outage condition, and, because it was constructed with lightning protection, the new line reduces lightning-caused voltage sag events in the area.

**Q. Did PacifiCorp consider alternatives to investing in the Wallula to McNary 230 kV New Transmission Line project?**

A. In lieu of the selected project, PacifiCorp considered re-building the existing Wallula to McNary 230 kV transmission line to a double circuit line, but this project had an estimated cost of $73.6 million. As a second alternative, PacifiCorp considered reconductoring the existing Wallula to McNary 230 kV transmission line with high temperature conductor. This alternative would have required the addition of phase shifting transformers to produce increased flow on the line and a new substation to place the equipment at an estimated cost of $53.6 million. Both alternatives were rejected due to cost savings associated with investing in the Wallula to McNary 230 kV New Transmission Line project.

## SNOW GOOSE 500/230 KV NEW SUBSTATION

**Q. Please describe the investment for the Snow Goose 500/230 kV New Substation project.**

A. This in-service project constructed a new 500/230 kV substation located near Klamath Falls, Oregon, as shown on the map attached in Exhibit No. RAV-5. The new Snow Goose substation has a 500/230 kV, 650 MVA transformer bank and associated switchgear. In addition, PacifiCorp constructed 0.5 miles of 230 kV transmission line and 1.2 miles of 500 kV transmission line to integrate the substation into the area's 230 kV and 500 kV systems. The 230 kV yard was placed in service in May 2017, and the 500 kV yard was placed in service in November 2017, for a total of $42.8 million. A one-line diagram of the Snow Goose 500/230 kV New Substation project is also included in Exhibit No. RAV-5.

**Q. Please explain the benefits of this investment in the Snow Goose 500/230 kV New Substation and why it is needed.**

A. The need for the Snow Goose 500/230 kV New Substation project was based on achieving continued compliance with reliability standards mandated by NERC under the TPL Standards. In 2012, PacifiCorp performed TPL Standards screening studies that identified system performance deficiencies following the single contingency loss of PacifiCorp's existing 500/230 kV, 650 MVA transformer bank at Malin substation. Specifically, PacifiCorp determined that during the 2017 projected summer peak load conditions, the loss of the transformer bank would result in the system failing to meet the low voltage limits on the PacifiCorp-owned 230 kV, 115 kV and 69 kV systems and an increase in the load on the Copco-Lone Pine 230 kV line. By 2027, the Copco-Lone Pine 230 kV line would exceed its rated thermal continuous and emergency capacity during this outage. This outage would also cause a reduction of the power flow on the Alturas-Reno Western Electricity Coordinating Council Path 76. As a result, firm scheduled transfers on this line could not continue to be supported without a second 230 kV source.

Construction of the Snow Goose substation provided a second 500 kV to 230 kV transmission tie in the area that ensured that PacifiCorp is able to maintain adequate system voltage and power delivery during a single contingency outage condition, thus maintaining service for customers in southern Oregon and northern California.

**Q. Did PacifiCorp consider alternatives to investing in the Snow Goose 500/230 kV New Substation Project?**

A. In lieu of the Snow Goose 500/230 kV New Substation project, PacifiCorp considered resolving the deficiencies under the TPL Standards by installing a second transformer at Malin substation and building a second line from Malin to Klamath Falls. This alternative was rejected as Malin substation could not be readily expanded to accommodate a new 500/230 kV transformer position due to physical site constraints. This alternative was estimated to be $85.0 million.

A second alternative would have involved installing a 500/230 kV, 650 MVA transformer at the BPA-owned Captain Jack substation and building 27 miles of 230 kV line from Captain Jack to Klamath Falls. Adding another transformer at Captain Jack substation would require increasing the size of the substation property and reaching an agreement with BPA. This alternative was estimated to be $90.0 million and was rejected because of insufficient space at the BPA-owned Captain Jack substation, inadequacy of the site in serving as a new source of 69 kV to the Klamath Falls metropolitan area, and additional reinforcement requirements of the 230 kV path between Captain Jack and Klamath Falls substations.

The last alternative considered would have involved installing a 500/230 kV, 650 MVA transformer at the Klamath Co-Gen substation and building a new 230 kV line to tap the Klamath Falls-Boyle 230 kV line. As with the first alternative, this option was rejected due to space and cost limitations. Estimated costs for this alternative were $85.0 million.

**VANTAGE TO POMONA HEIGHTS 230 KV NEW TRANSMISSION LINE**

**Q. Please describe the investment for the Vantage to Pomona Heights 230 kV New Transmission Line.**

A. The Vantage to Pomona Heights 230 kV New Transmission Line project consists of a new 41-mile, 230 kV transmission line that extends from the BPA Vantage substation near Vantage, Washington, and ends at the PacifiCorp Pomona Heights substation in Yakima, Washington, as shown on the map attached in Exhibit No. RAV-6. The project consists of two sequences of work. The first work sequence to expand the Pomona Heights substation 230 kV ring bus to provide adequate breaker separation between lines and transformers for breaker failure and bus fault events was placed in service in November 2015 for $9.4 million, and was included in rate base as part of the 2015 Rate Case. The second sequence of work is projected to be placed in service in May 2020 for an estimated $57.3 million and includes the installation of a new 230 kV transmission line connected at BPA's Vantage substation and ending at PacifiCorp's Pomona Heights substation. The Company has now received full federal permissions to construct this transmission line. The final segment permission was received from the Bureau of Labor on September 27, 2019. This portion of the project will include the installation of breakers, protection and control equipment, and communications equipment at each substation as required to monitor and safely operate the new line. The infrastructure additions at Vantage substation will be designed, purchased, installed, and maintained by BPA. A one-line diagram of the

Vantage to Pomona 230 kV New Transmission Line project is also included in Exhibit No. RAV-6.

**Q. Please explain why this investment in the Vantage to Pomona Heights 230 kV New Transmission Line is needed and beneficial.**

A. The need for the Vantage to Pomona Heights 230 kV project was identified through internal planning studies and a coordinated Northwest Transmission Assessment Committee study in 2007. NERC screening studies conducted in 2009 and subsequent NERC screening studies additionally identified TPL Standards performance deficiencies following breaker failure and bus fault events on the Pomona Heights 230 kV bus and various N-1-1[15] outages associated with the Wanapum to Pomona Heights 230 kV line. Breaker failure and bus fault and N-1-1 events on other portions of the Yakima 230 kV and 115 kV systems result in additional TPL Standards performance deficiencies. In total, there are eight contingency combinations that were identified that could give rise to the need to shed Yakima area load. The Yakima area is currently served primarily by two 230 kV transmission sources. The loss of both primary 230 kV sources or loss of one primary 230 kV source and another major element in the underlying system leaves the remaining system unable to provide adequate electric service to all customers in the area.

The addition of a new 230 kV line between Vantage and Pomona Heights substations and providing a third 230 kV source to the area mitigates the identified deficiencies. Specifically, the project eliminates the need to shed Yakima area load

[15] See footnote 2 for a description of N-1-1 events.

for those eight contingency combinations and eliminates overloads in the PacifiCorp and BPA transmission systems with loss of the existing line.

By enabling PacifiCorp to comply with the TPL Standards and increasing the reliability of PacifiCorp's transmission system by eliminating the need to shed Yakima area load under certain outage conditions, this project provides benefits to customers.

**Q. Did PacifiCorp consider alternatives to investing in the Vantage to Pomona 230 kV New Substation Project?**

A. In lieu of the selected project, the new 230 kV line from Vantage to Pomona Heights, PacifiCorp considered constructing a new 500/230 kV transformer and bus position at Wautoma substation and a new 230 kV transmission line from Wautoma substation to Pomona Heights substation resulting in an estimated cost of $89.6 million. This alternative was rejected because the costs were higher than the selected project. Another alternative would have involved constructing a second 230 kV transmission line from Midway substation to Union Gap substation. This alternative was rejected, however, because it would have corrected identified deficiencies for only approximately 10 years before additional transmission reinforcement would be required.

## GOSHEN-SUGARMILL-RIGBY 161 KV TRANSMISSION LINE PROJECT

**Q. Please describe the investment for the Goshen to Sugarmill to Rigby 161 kV Transmission Line project.**

A. The Goshen-Sugarmill-Rigby 161 kV Transmission Line project constructs approximately 44 miles of new transmission lines from the Goshen to Sugarmill and

Sugarmill to Rigby substations located in the southeast Idaho area. Substation expansion will be required at Goshen, Sugarmill, and Rigby substations to accommodate the new 161 kV positions and associated structures and equipment, as shown on the map attached in Exhibit No. RAV-7. The project consists of two sequences of work. The first work sequence, planned to be placed in service in November 2020 for $21.5 million, is to construct approximately 24 miles of the new Goshen to Sugarmill #2 161 kV transmission line and perform the required substation construction at Goshen and Sugarmill substations to terminate the new transmission line at both ends. The new 161 kV line consists of approximately 22.2 miles of 69 kV line rebuilt to 161 kV and 1.6 miles of new double circuit construction into Sugarmill substation. Substation work includes yard expansion for adding the new 161 kV line positions and installation of transmission dead-end structures, substation bus and associated disconnect switches and breakers. The substation work also includes the installation of protection and control equipment, and communications equipment at each substation as required to monitor and safely operate the new line. The second work sequence is planned to be placed in service in November 2022, which falls outside of the scope of this case. The second sequence will consist of constructing approximately 20 miles of the new Sugarmill to Rigby #2 161 kV line and performing the required substation construction at Goshen and Sugarmill substations to terminate the new transmission line at both ends of the line.

**Q. Please explain why this investment in the Goshen to Sugarmill to Rigby 161 kV Transmission Line project is needed and beneficial.**

A. The need for the Goshen to Sugarmill to Rigby 161 kV Line project was identified in the 2016 Goshen Area Planning Study to address projected overloads on the Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line, in addition to low voltage at Rigby and Sugarmill substations that manifest under heavy loading conditions. Projected peak summer load conditions in 2021 in the Rigby-Sugarmill area indicate that under normal operating conditions (N-0) the Goshen to Sugarmill 161 kV line is expected to load to 100 percent of its continuous rating of 201 MVA and the Rigby and Sugarmill substations 161 kV bus voltage is expected to reach its minimum limit of 0.95 per unit. Additionally, the projected load growth exacerbates several existing N-1 conditions in the area. Based on 2021 load, loss of the Goshen to Sugarmill 161 kV line causes the Goshen to Rigby 161 kV line to overload to 179 percent of its four-hour emergency rating and can result in excessively low voltage down to 0.68 per unit in the Rigby-Sugarmill area. The loss of the Goshen to Rigby 161 kV line can cause the Goshen to Sugarmill 161 kV line to overload to 111 percent of its four-hour emergency rating of 255 MVA, overload to 102 percent of its 30-minute emergency rating of 279 MVA, and can cause low voltage down to 0.88 per unit at Rigby substation. The Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line are operated radially during summer heavy loading periods to mitigate the risk of violating NERC Standard TPL-001-4 category P0 (N-0), P1 (N-1) and P6 (N-1-1) performance requirements due to transmission capacity deficiencies in the area. Operating radially puts approximately 150 MW load at risk for N-1 loss of either the Goshen to Sugarmill 161 kV line or the Goshen to Rigby 161 kV line and 300 MW at risk for N-1-1 loss of any two transmission lines.

The new Goshen-Sugarmill-Rigby 161 kV Line project will increase load serving capacity in the Rigby-Sugarmill area by 250 MVA that will allow the transmission lines between Goshen, Sugarmill, and Rigby substations to operate in a normal loop configuration and N-1 thermal overload and low voltage issues on the remaining transmission line and substation. Benefits also include elimination of the N-0 overload risk, improved load service reliability under N-1 conditions, and resolution of most N-1-1 issues present in the area.

**Q. Did PacifiCorp consider alternatives to investing in the Goshen to Sugarmill to Rigby 161 kV Transmission Line project?**

A. Yes. The first alternative in lieu of the Goshen-Sugarmill-Rigby 161 kV Line project that PacifiCorp considered was a project to construct a new approximately 35-mile long Goshen to Rigby 345 kV line with 1272 aluminum conductor steel-reinforced (ACSR) cable and add a new 450 MVA capacity or larger 345-161 kV transformer at the Rigby substation. Work involved expanding both the Goshen and Rigby substation yards to accommodate the new facilities consisting of at least two 345 kV breakers at Goshen, one 345 kV breaker at Rigby and at least two 161 kV breakers at the Rigby 161 kV substation. This alternative was rejected since the estimated cost of the project was about $17.0 million higher than the chosen project to construct the new Goshen-Sugarmill-Rigby 161 kV transmission line. The alternative was estimated to be $57.7 million.

A second alternative considered was to construct an approximately 61-mile-long Antelope to Rigby 161 kV transmission line with 1272 ACSR cable or larger. Work involved expanding both the Antelope and Rigby substation yards to accommodate the new facilities consisting of at least at least two 161 kV breakers at Antelope and at least two 161 kV breakers at Rigby. A new 161 kV line from Antelope would provide a new source into the Rigby-Sugarmill area apart from Goshen substation; however, planning studies indicated that by adding the Antelope to Rigby 161 kV line, the N-1 loss of the Goshen to Sugarmill 161 kV line will still cause thermal overload and low voltage issues in the area and that load shedding and radialization of the Rigby-Sugarmill area would still be required. This alternative was rejected since the estimated cost of the project was about $8.0 million higher than the new Goshen-Sugarmill-Rigby 161 kV transmission line and that a new Antelope to Rigby 161 kV transmission line does not resolve the loading and voltage issues in the Rigby-Sugarmill area. The alternative was estimated to be $48.0 million.

A third alternative considered was to construct approximately 22.8 miles of a 161 kV transmission line from the Meadow Creek wind farm substation to Sugarmill and Rigby substations to create a looped transmission source back to Goshen substation. Work involved constructing approximately 5.9 miles of new single circuit 161 kV transmission line from Meadow Creek to a new tap location, using the existing right of way to construct 4.5 miles of double-circuit line from the new tap location to Sugarmill substation, and construct 12.4 miles of new single-circuit 161 kV line from the new tap location to Rigby substation. Work also included converting Meadow Creek's 161 kV substation yard into a new three breaker ring bus, installation of at least two 161 kV breakers at Sugarmill and Rigby substations, rebuilding the Goshen – Wolverine Creek – Jolly Hills – Meadow Creek 161 kV line with 1557 ACSR cable (approximately 32.4 miles), rebuilding the remaining three miles of 795 all-aluminum conductor (AAC) cable on the Goshen – Sugarmill 161 kV line and adding a 161 kV bus tie breaker at Rigby to facilitate sectionalizing post N-1. Currently, the Goshen wind farms are radial from the Goshen 161 kV substation. Once looped through the Rigby and Sugarmill substations, a detailed voltage control study would be required to coordinate the wind farms and shunt devices in the area. Since the existing radial wind farm line is owned and operated by third parties, an agreement to use or buy the facilities would need to be negotiated. This alternative was rejected since the estimated cost of the project was about $8.2 million higher than the new Goshen-Sugarmill-Rigby 161 kV transmission line project and required significant coordination with third parties to deliver the project. The alternative was estimated to be $48.5 million.

The last alternative considered was to loop the existing Goshen to Jefferson 161 kV transmission line in and out of the Bonneville substation. Work involved converting the Bonneville substation into a 161 kV breaker and one-half configuration, constructing an approximately 27-mile-long 161 kV line from Bonneville to Rigby substation with at least 1557 ACSR cable. Work also involved expanding both the Rigby substation yards to accommodate a new 161 kV line position consisting of at least two 161 kV breakers at the Rigby substation. Adding this new Bonneville to Rigby 161 kV line does not improve N-1 and N-1-1 issues in the area and therefore is not considered as a viable alternative. The estimate for this project was $33.2 million. Additional projects would be required to address the N-1 and N-1-1 issues. These projects include reconductoring 32 miles of Goshen to Rigby 161 kV line, reconductoring 16 miles of Sugarmill to Rigby 161 kV line and reconductoring 3.5 miles of 795 AAC cable on existing Goshen to Sugarmill 161 kV line. Additionally, a new Goshen – Sugarmill 161 kV line would be required to mitigate the low voltage and voltage swings caused by the loss of the existing Goshen to Sugarmill 161 kV line. The estimate to reconductor these lines was $6.6 million and the estimate to construct a new Goshen to Sugarmill 161 kV line was $13.3 million. This alternative was rejected since the estimate for the new Bonneville to Rigby 161 kV line and supporting projects was about $12.7 million higher than the recommended new Goshen-Sugarmill-Rigby 161 kV transmission line project. The alternative was estimated to be $53.1 million.

**GROMORE SUBSTATION-CONSTRUCT NEW 115-12.47 KV SUBSTATION**

**Q. Please describe the investment for the Gromore Substation project.**

A. This in-service project constructed a new 115-12.47 kV substation located in Yakima, Washington, as shown on the map attached in Exhibit No. RAV-8. The new Gromore substation has a 115-12.47 kV, 25 MVA transformer bank, metal-clad switchgear, and one initial distribution feeder. In addition, PacifiCorp constructed 179.5 feet of 115 kV transmission tap line to loop the Tieton to Wiley 115 kV transmission line segment through the new Gromore substation. The new 115-12.47 kV substation was placed in service in April 2018, and the associated 12.47 kV feeder work was placed in service in May 2018, for a total of $7.6 million of plant placed in service. A one-line diagram of the new Gromore Substation is included in Exhibit No. RAV-8.

**Q. Please explain why this investment in the new Gromore Substation project is needed and beneficial.**

A. The need for the Gromore Substation project was driven by substation transformer peak loading issues at Wiley and Orchard substations in the Yakima area. Measurements in 2015 identified the Wiley substation transformer T-3256 reached 100 percent of its equipment winter nameplate rating[16] and transformer T-3676 reached 96 percent of its equipment summer nameplate rating. Measurements in 2015 also identified Orchard substation transformer T-3797 reached 97 percent of its equipment summer nameplate rating and transformer T-5035 reached 105 percent of equipment summer nameplate rating. Annual winter peak load growth rate for Wiley transformer T-3256 was approximately 2.4 percent and the annual summer peak load growth rate for Orchard transformer T-5035 was approximately 1.3 percent, which placed continued pressure on the transformers already at or in excess of their respective nameplate ratings. Exposing the substation equipment to peak loading in excess of nameplate ratings creates additional stress on the equipment, which increases the risk of equipment loss of life and equipment failure, and raises reliability concerns.

The new Gromore Substation project achieved peak load relief to Wiley and Orchard substation transformers and distribution feeders through load transfers which moved load off the aforementioned substations and feeders to the new Gromore substation and its new 12.47 kV feeder. Benefits also include increasing capacity on

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[16] Equipment nameplate ratings represent the loading a piece of equipment can handle for extended operations before deterioration occurs and/or possible equipment failure. Emergency ratings allow for shorter duration loading, above nameplate ratings, to handle temporary loading conditions.

transformers and feeders at Orchard and Wiley substations and improving reliability of the distribution feeders by reducing line exposure and line loading in the 12.47 kV distribution network. This project also located the Gromore substation near the current load growth area for new residential and agricultural load in Western Yakima.

**Q. Did PacifiCorp consider alternatives to investing in the Gromore Substation project?**

A. Yes. The first alternative in lieu of the new Gromore Substation project PacifiCorp considered was a project to increase capacity at Wiley substation and build a new distribution feeder. Work involved included replacing the 20 MVA, 115-12.47 kV transformer T-3256 with one rated 25 MVA, constructing a new 12.47 kV feeder and reconductoring 4,800 feet of 336 AAC to 795 AAC on 5Y454. This alternative was rejected since load center is several miles away and was anticipated to reach its capacity in 10 to 15 years, at which time a new substation would need to be built. The alternative was estimated to be $5.4 million. The final spend to do this alternative first, and build a new substation in 10-15 years, was estimated to be a combined $11.5 million.

A second alternative considered matching the capacity increase of the proposed new Gromore Substation project by expanding the existing Wiley substation to include a new 25 MVA transformer and build of a new feeder to serve the load area. Work involved expanding Wiley substation yard which required purchasing additional property, installing a new 25 MVA, 115-12.47 kV transformer, constructing a new 12.47 kV feeder position and reconductoring 4800 feet of 336 AAC to 795 AAC on feeder 5Y454. This alternative was rejected since the exiting

Wiley feeders are fully utilized, which would require an additional feeder to be built and extended several miles away to serve load growth areas that are near the proximately of new Gromore substation. As with the first alternative, a new substation would eventually be needed in the area of the new Gromore substation to serve anticipated load growth northwest of Wiley substation. This alternative was estimated to be $7.0 million.

A third alternative considered was to transfer load from Orchard substation to Clinton substation. Based on the available capacity at Clinton, Orchard could see some initial load relief by transferring load from Orchard substation to Clinton substation. In order to do this, a four-mile distribution feeder extension would be required for load balancing and transfer. This alternative was rejected considering the agricultural load growth that has been occurring in this area and the fact that this alternative does not resolve the loading issues at Wiley. To address the capacity issues at Wiley, the second alternative would need to be combined with the third alternative. The third alternative was estimated to be $2.0 million. Combining the second and third alternatives was estimated to be $9.0 million.

The last alternative considered utilized a Distribution Energy Resource (DER) or Demand Side Management (DSM) alternative. There is not an existing DSM option that can accomplish the peak shaving requirements needed. However, there is a storage battery alternative that can address a peak load reduction of 4 MVA. This alternative was rejected because achieving 4 MVA of peak load shaving utilizing battery storage would come at a cost very close to what was required to deliver the new Gromore Substation project and would provide significantly less capacity than the new Gromore Substation project. Gromore substation provides 25 MVA of capacity for a much longer term solution at a significantly lower cost per MVA than the storage battery alternative. This alternative was estimated to be $7.5 million.

**STADELMAN FRUIT**

**Q. Please describe the investment for the Stadelman Fruit project.**

A. This in-service project increased 115-12.47 kV transformer capacity at Punkin Center substation by 25 MVA and built a new distribution feeder to facilitate load transfer relief at Toppenish substation and its Zillah feeder in Yakima, Washington, as shown on the map attached in Exhibit No. RAV-9. Increasing capacity at Punkin Center substation was achieved by construction activities to install a new 115-12.47 kV transformer, expand the 115 kV bus, install new 12.47 kV metal-class switchgear and install one initial distribution feeder. In addition, PacifiCorp re-terminated the 115 kV transmission line from Outlook substation on a new structure, installed a 115 kV transrupter and moved the mobile connection to the east side of the substation yard. Distribution network upgrade work included construction for 200 feet of 1000 CU underground feeder getaways, construction of 4,000 feet of new 795 AAC overhead primary conductor, reconductoring of 20,000 feet of existing single and three phase overhead line to 795 AAC primary and other associated distribution feeder work. The increase capacity work at Punkin Center substation was placed in service in June 2016 and the associated distribution feeder work was placed in service in July 2017, for a total of $6.8 million of plant placed in service. A one-line diagram of the Punkin Center 115-12.47 kV substation project is also included in Exhibit No. RAV-9.

**Q. Please explain why this investment in the Stadelman Fruit project was needed and beneficial.**

A. The need for the increase capacity at Punkin Center substation project was driven by Stadelman Fruit LLC's request for addition load service of 1.5 MVA at its Zillah, Washington facility that could not be accommodated from the Zillah distribution feeder from Toppenish substation that served the existing facilities load at the time of the request. The proposed 1.5 MVA load addition would have overloaded the Zillah feeder by 147 percent and placed the Toppenish substation transformers at 107 percent of their nameplate rating based on 2015 summer loading measurements. The load addition could not be accommodated by distribution load transfers as all load transfer options had been exercised at the time and there were no effective feeder ties to neighboring systems. Without the capacity increase, the thermal loading introduces a high risk for equipment or conductor failure on the Zillah feeder and exposes the substation transformers to overload stresses that increase the risk of equipment loss of life and equipment failure.

The increased capacity at Punkin Center substation and the installation and buildout of the new Punkin Center feeder achieved peak load relief to Toppenish substation and the Zillah feeder through load transfers which delivered the 1.5 MVA additional load service to Stadelman Fruit. Benefits also included increased capacity on transformers and feeders at both Toppenish and Punkin Center substations, established load transfer capability between Toppenish and Punkin Center substation, improved outage restoration times and lower maintenance costs for distribution and substation work. Before completion of the projects, maintenance options were restricted during peak load periods, and installation of a mobile was required for any outage related work.

**Q. Did PacifiCorp consider alternatives to investing in the Stadelman Fruit project?**

A. Yes. The first alternative in lieu of the increased capacity at Punkin Center substation project PacifiCorp considered was to transfer load to a Toppenish feeder and reconductor the feeder mainline. Work involved upgrading line conductor to improve load transfer capability in the Buena-Zillah area served from Toppenish substation to free up capacity on the Zellah feeder for the additional load addition for Stadelman Fruit. The load transfer between the feeders would create enough transformer and line capacity to connect Stadelman Fruit; however, the 1.5 MVA additional load would have immediately put the transformer loading back to 100 percent of name plate. This alternative was rejected since it eliminated any room for growth in the area and would still require an immediate capacity relief solution for Toppenish Substation. The alternative was estimated to be $1.2 million and would have required further investment similar to the chosen alternative to address longer term capacity support in the area.

A second alternative considered was to construct a new substation near Zillah, Washington, and reroute the transmission line. Work involved constructing a new 115-12.47 kV substation near the City of Zillah and rerouting the 115 kV transmission line to provide a 115 kV source to the new substation. This alternative would have provided capacity relief to both Toppenish and Punkin Center substations and feeders in a similar way as the chosen capacity increase at Punkin substation project delivered. This alternative required a property purchase and transmission right of way acquisition. The 115 kV transmission line would be rerouted between Punkin Center and Toppenish to provide the loop connection for service in and out of the new substation. This was an effective long-term solution that sited the substation near the area with the largest projected future growth. If time constraints were not a factor, this would have been the most desirable long term option. This alternative was rejected due to the length of time needed to construct, unknowns related to property and right of way acquisition, and the solution not being able to meet the customer's timeline requirements. This alternative was estimated to be $11.5 million.

A third alternative considered was to add capacity at Outlook substation. Work involved installation of a new 115-12.47 kV transformer and feeder position with switchgear at Outlook Substation. This alternative necessitated an extended construction period because it required significantly more new distribution infrastructure. The permitting and right of way implications created a significant risk of not being able to meet the customer's requested in-service date. This alternative was rejected due to the high risk that this solution could not be delivered in time to meet the required schedule. This alternative was estimated to be $7.6 million.

A fourth alternative considered was to add capacity at Punkin Center substation by replacement of both existing transformers with higher capacity transformers. Work involved replacing the two 115-12.47 kV, 9.375 MVA, transformers at Punkin Center substation with new 115-12.5 kV, 14 MVA, transformers. If fruit packing expansion continued in the area, the need to make larger infrastructure changes in the near term remained likely. A temporary substation would have needed to be constructed on the east side of the Punkin Center substation property or a mobile transformer installed for six to eight months while each transformer was replaced.  This alternative was rejected due to it being a higher cost solution, providing a smaller capacity increase with less load transfer and restoration flexibility than the chosen alternative, and that it could not be completed in time to meet the customer's required in-service date.  This alternative was estimated to be $9.0 million.

## CONCLUSION

**Q. Please summarize your testimony.**

A. I recommend that the Commission determine that the projects stated above will provide benefits to Washington customers and are therefore prudent and in the public interest.

**Q. Does this conclude your direct testimony?**

A. Yes.