Rocky Mountain Power
Docket No. 20-035-04
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Rick A. Vail

May 2020

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Company").

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, transmission capital budgeting, transmission and distribution project delivery, and administration of the Open Access Transmission Tariff ("OATT"). I am testifying on behalf of the Company.

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.

II. 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 Utah 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 and participation in the Energy Imbalance Market 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 describe the status of PacifiCorp's construction of the Aeolus-to-Bridger/Anticline 500 kilovolts ("kV") Transmission Line and the additional 230 kV network upgrades required to interconnect the Energy Vision 2020 Wind projects ("230 kV Network Upgrades"). I specifically address the current timeline and estimate of costs.

I also describe PacifiCorp's major capital investment projects for new transmission systems included in this rate case, specifically:

- Wallula to McNary 230 kV Transmission Line;
- Snow Goose 500/230 kV Substation;
- Vantage to Pomona Heights 230 kV Transmission Line;
- Goshen-Sugarmill-Rigby 161 kV Transmission Line; and
- Goshen #3 345/161 kV 700 Megavolt-Ampere ("MVA") Transformer Installation.

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 Utah. I recommend that the Utah Public Service Commission ("Commission") find these investments prudent and in the public interest.

III. 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 kV to 500 kV across multiple western states. PacifiCorp serves over 1.9 million customers with approximately 948,710 customers located in Utah.

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] 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

[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).

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 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

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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).

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

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 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

[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.

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 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 transmission system described in your testimony.

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

IV. OVERVIEW OF INVESTMENTS DESCRIBED IN TESTIMONY

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

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

1. Aeolus to Bridger/Anticline Line and network upgrades associated with new wind generation interconnections:

The new transmission lines consists of 140 miles of 500 kV transmission line; the new Aeolus (500/230 kV) and Anticline (500-345 kV) substations; a five-mile, 345 kV transmission line from the Anticline substation to the Jim Bridger substation; a voltage control device at the existing Latham substation. The 230 kV Network Upgrades are required to accommodate the transmission project and the interconnection of the Energy Vision 2020 New Wind Projects.

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 RMP___(RAV-1).

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 RMP___(RAV-2).

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 RMP___(RAV-3).

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 RMP___(RAV-4).

6. Goshen #3 345/161 kV 700 MVA Transformer Installation:

The Goshen #3 345/161 kV 700 MVA transformer installation project located in southeast Idaho, as shown in the map attached in Exhibit RMP___(RAV-5).

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

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

Table 1 – Transmission Investment		
Project	**Total Company Cost ($ million)**	**In-Service Date**
Aeolus to Bridger/Anticline 500 kV line[5]		
Sequence Two (In-Service)	$4.1	July 2018
Sequence Three (In-Service)	$12.7	January 2020
Sequence Four	$660.3	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	$57.8	May 2020
Goshen-Sugarmill-Rigby 161kV Transmission Line Project		
Sequence One	$21.7	November 2020
Sequence Two (not included in this case)	N/A	November 2022
Goshen #3 345/161 kV 700 MVA Transformer Install TPL		
Sequence One	$17.2	November 2020
Sequence Two	$6.1	November 2021

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

These amounts include costs associated with engineering, project management, materials and equipment, construction, right-of-way, and an allowance for funds used during construction. These costs are also shown in the testimony and exhibits of Mr. Steven R. McDougal. The in-service dates are based on the best available information at the time of preparing this case.

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, and relief of existing congestion. 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.[6] 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

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

included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions.

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[7] and retail rate base.

Q. Please describe the investment for the Aeolus to Bridger/Anticline transmission line that is included in the Energy Vision 2020.

A. The Aeolus to Bridger/Anticline transmission line 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 was completed in March 2011. The second

[7] 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).

sequence was to construct a replacement access bridge over the Medicine Bow River and complete associated upgrades to an existing unpaved county road in July 2018. The third sequence of work, completed in January 2020, was the expansion of the Latham Substation with a new line termination bay to accommodate the installation of a Static Synchronous Compensator voltage control device. Finally, the last sequence of plant in-service includes the two 500 kV substations (i.e. Aeolus and Anticline) and the 500 kV transmission line in December 2020.

Q. Has the Company made substantial progress on construction of the Aeolus to Bridger/Anticline Line?

A. Yes. The Company has all contracts for construction of the Aeolus to Bridger/Anticline transmission line in place. Construction work commenced in April 2019. As of April 2020, the 500 kV transmission line had 100 percent of all foundations installed, 91 percent of structures erected and 46 percent of wire stringing completed. The Aeolus, Anticline, and Jim Bridger substations are under construction with grading complete and foundation installations, as well as underground construction, which is ongoing. Steel erection and bus installation has commenced at Aeolus, Anticline, and Jim Bridger substations. Major substation equipment is being manufactured and tested; first deliveries of circuit breakers have been received at all three substations, capacitor banks and reactive devices were delivered in December 2019, and the transformers will begin arriving in spring 2020. The Latham substation expansion is now complete and was placed in-service in January 2020.

Q. Please describe the 230 kV Network Upgrades associated with the Energy Vision 2020 Projects.

A. The generation interconnection projects selected as part of a request for proposal to interconnect 1,150 megawatts ("MW") of new wind generation to the transmission system in eastern Wyoming were fully described in Docket No. 17-035-40 and are summarized below. Separate generation interconnection agreements were negotiated and signed for each of the projects.

The Ekola Flats network upgrades are planned to be placed in-service in December 2020. This work includes one 230 kV circuit breaker and one line position with associated switches, which are included in the Aeolus substation scope of work. As such there are no stand-alone network upgrade costs associated with the Ekola Flats project.

The TB Flats I and II network upgrades are planned to be placed in-service in December 2020. 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.

The Cedar Springs network upgrades are planned to be placed in-service in December 2020. 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. Has the Company obtained all of the necessary permits and rights-of-way for the transmission and network upgrade projects?

A. Yes.

Q. Is the Company confident that it can manage the construction schedule risk and deliver the Aeolus to Bridger/Anticline transmission line and the 230 kV Network Upgrades for the new wind facilities of Energy Vision 2020 by year-end 2020?

A. Yes. To manage construction schedule risk, the Company structured each of the Aeolus to Bridger/Anticline contracts and the 230 kV Network Upgrades contracts on a firm, date-certain, fixed-price, turnkey contract basis. Construction contractors and equipment suppliers are being held to key construction and delivery milestones and development of compressed schedule mitigation plans, if required.

Q. Please expand on some of the elements that will help the Company manage the risk of delay.

A. In its contracts, the Company set contractual milestones well in advance of the December 2020 project in-service date for all elements of the transmission and substation projects, and the 230 kV Network Upgrades. If needed to mitigate unforeseen circumstances, the contractor and the Company are prepared to implement compressed schedule mitigation plans.

Q. Has the Company implemented any contingency options on a project to date?

A. Yes. PacifiCorp instituted a contingency plan for two components of the 230 kV Network Upgrades. Construction work was hampered during the winter/spring seasons of 2020 on account of severe winter weather. The Bureau of Land Management imposed stringent winter game restrictions that adversely affected construction. The dates affected by the additional Bureau of Land Management restrictions were the May 2020 estimated completion dates for two transmission line segments of the 230 kV Network Upgrades: Aeolus to Shirley Basin and Aeolus to Freezeout.

The only impact from the additional restrictions was an anticipated delay to supplying back-feed power to the Ekola Flats wind project, which is needed by June 15, 2020. The Company, however, implemented a contingency plan that will supply the back-feed power needed, on a temporary basis, by June 15, 2020 date, and is working with the contractor to modify the contractual substantial completion dates of the Aeolus to Shirley Basin and Aeolus to Freezeout transmission lines to October 31, 2020. At this point, no other contingency solutions are required to ensure the project in-service date of December 2020.

Q. What are the major milestones remaining before the December 2020 in-service date for the Aeolus to Bridger/Anticline transmission line and 230 kV Network Upgrades?

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 to Shirley Basin Substantial Completion: October 31, 2020[8]
- Aeolus to Freezeout Substantial Completion: October 31, 2020[9]
- Freezeout to Standpipe Substantial Completion: September 15, 2020
- Aeolus to Shirley Basin (rebuild) Substantial Completion: September 30, 2020

Q. Please describe the estimated total cost of the Aeolus to Bridger/Anticline transmission line.

A. The forecasted costs of the Aeolus to Bridger/Anticline transmission line remain at approximately $679.2 million, the amount approved in Docket No. 17-035-40, and as summarized in Table 2.

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

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

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[8] Changed from May 15, 2020, due to additional restrictions imposed by the Bureau of Land Management.
[9] Changed from May 30, 2020, due to additional restrictions imposed by the Bureau of Land Management.

Q. Please describe the estimated total cost of the 230 kV Network Upgrades.

A. The 230 kV Network Upgrades are now estimated to cost $92.2 million, as summarized in Table 3 below. This is approximately $14.9 million more than the estimate that received pre-approval from the Commission.[10]

Table 3	
Item	**Total Company Value ($ million)**
Transmission Line	$53.15
Substations	$12.67
Engineering	$3.7
ROW Acquisition	$1.1
PM/Environmental/Support Works	$9.15
In-directs	$9.69
Contingency	$2.78
TOTAL	**$92.2**

Q. What are the drivers for the cost increase?

A. The increase in cost was due to the competitive bid price received for the transmission line elements of the 230 kV Network Upgrades, which exceeded the initial forecast value. The increase in transmission line costs are attributable to market conditions that changed after the initial cost estimate was prepared in early 2018 and approved by the Commission in Docket No. 17-035-40. The estimate was prepared using historical metrics to develop a cost plan, which could not have accounted for the rapid expansion of projects in the industry that occurred just prior to the time of the bid, including

[10] *Application of Rocky Mountain Power for Approval of a Significant Energy REsource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40, Order at 37 (Jun. 22, 2018).

Pacific Gas & Electric Company's transmission improvement program, initiated in response to extensive wildfires in California.

Q. Did the Company issue a request for proposals for the 230 kV Network Upgrades?

A. Yes. The competitively bid price reflected excess demand on lineman resources as a result of the increased project demand. In addition, the increase in projects also created cost impacts on steel and other materials. Several potential bidders who had previously done work for PacifiCorp declined to bid, citing lack of resources as their reason. Nevertheless, a subsequent final competitive auction among finalist bidders resulted in an approximate 4.5% reduction from the original bid value.

Q. Why was there an increase for the 230 kV Network Upgrades but not for the Aeolus to Bridger/Anticline transmission line?

A. The Company sought bids for the Aeolus to Bridger/Anticline transmission line earlier in the process. The construction requirements in California following the wildfires, however, changed the market conditions when the Company went to bid the 230 kV Network Upgrade projects.

V. WALLULA-MCNARY 230 KV NEW TRANSMISSION LINE

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

A. The 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. 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 RMP___(RAV-1).

Q. Please explain why this investment in the Wallula to McNary 230 kV New Transmission Line project was necessary.

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. The 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 new resources.

In addition, the project enhances transmission reliability by providing a second connection between the Bonneville Power Administration's ("BPA") McNary substation and PacifiCorp's Wallula substation. With only a single line between Wallula and McNary, line outages (either planned or unplanned), historically caused disruption of service to customers. This disruption resulted in loss of service under existing contracts or reduced reliability for customers served from the Wallula substation. The 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. Yes. 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 re-conductoring 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.

VI. SNOW GOOSE 500/230 KV NEW SUBSTATION

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

A. This project consisted of constructing a new 500/230 kV substation located near Klamath Falls, Oregon, as shown on the map attached in Exhibit RMP___(RAV-2). 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 RMP___(RAV-2).

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

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 WECC 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 ensuring 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. Yes. 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.

VII. 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 consists of a new 41-mile, 230 kV transmission line that extends from BPA's Vantage substation near Vantage, Washington, and ends at PacifiCorp's Pomona Heights substation in Yakima, Washington, as shown on the map attached in Exhibit RMP___(RAV-3). 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. The second sequence of work is projected to be placed in-service in May 2020 for an estimated $57.8 million and includes the installation of a new 230 kV transmission line connected at BPA's Vantage substation and ending at the 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 Land Management 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 is also included in Exhibit RMP___(RAV-3).

Q. Please explain why this investment in the Vantage to Pomona Heights 230 kV New Transmission Line is necessary.

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 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 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. Yes. 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 because it would have only corrected the identified deficiencies for approximately 10 years before additional transmission reinforcement would be required.

VIII. 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 consists of constructing approximately 44 miles of new transmission lines from the Goshen to Sugarmill and Sugarmill to Rigby substations located in southeast Idaho. 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 RMP___(RAV-4). The project consists of two sequences of work. The first work sequence, planned to be in-service in November 2020 for $21.7 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 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 necessary.

A. The need for the Goshen to Sugarmill to Rigby 161 kV line 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 of 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 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 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 approximately 61 miles of 161 kV transmission line from Antelope to Rigby 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 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 would 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 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 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.

IV. GOSHEN #3 345/161 KV 700 MVA TRANSFORMER INSTALLATION PROJECT

Q. Please describe the Goshen #3 345/161 kV 700 MVA transformer project.

A. The Goshen #3 transformer project is to install a third 345/161 kV transformer at the Goshen substation, located in southeast Idaho, and expand the 161 kV yard to accommodate a new feed from the 345 kV yard. In addition, various 161 kV lines will be relocated and the existing Goshen 161 kV dual operate bus will be converted into a breaker and one-half 161 kV scheme. Redundant 161 kV relays will also be installed. The project will use a spare 345/161 kV transformer that was delivered in March 2018 and a spare 345/161kV transformer will be purchased to be located at the Gadsby Plant as required per PacifiCorp grid resiliency plan. The Company is expecting this project to be in-service in November 2020. The spare replacement transformer is expected to be received in November 2021 for $6.1 million.

Q. Please explain why the Goshen #3 345/161 kV 700 MVA transformer project is necessary.

A. The Goshen #3 transformer installation project will resolve NERC TPL-001-4 Category P1-3 (N-1) thermal overloading issues on the existing Goshen transformers beginning in 2021. The Goshen substation has two 345/161 kV 450 MVA transformers which serve the load in the area. As loads in the Goshen area increase, the risk of overloading one of the existing Goshen transformers due to the loss of the other increases as well. The 2016 Goshen area studies indicated that by 2021, loss of either one of the Goshen 345/161 kV transformers can overload the remaining Goshen

345/161 kV transformer above its emergency rating. Historical Goshen area load and generation data for the 2013-2017 period indicated that the average risk of overloading one of the Goshen 345/161 transformers under an N-1 condition was 10.5 percent each year (915 hours/38 days-the average number hours each year where area generation was below 200 MW and load was in excess of 450 MW). Since a transformer outage is a potential long term outage (up to 18 months to order and install a new transformer), the risk of overloading one of the Goshen transformers could be present for an extended period, or until the spare can be installed which would take 2-3 months.

Q. Did PacifiCorp consider alternatives to investing in the Goshen #3 345/161 kV 700 MVA transformer installation project?

A. Yes. The first alternative considered was to add a new 345/161 kV transformer at the Rigby substation. However, since the Rigby substation does not have a 345 kV source, a new 35-mile-long 345 kV line from the Goshen to Rigby substation would have been required. This alternative would have also required at least two 345 kV breakers at the Goshen substation and one 345 kV breaker and one 161 kV breaker at the Rigby substation. In addition an expansion of the Rigby substation yard would have been necessary to accommodate the new 345 kV bus, transformer, breakers etc. An estimate of this project is $71 million. This alternative was not selected due to significantly higher cost than the preferred solution.

The second alternative considered was to construct an approximately 61-mile-long 161 kV line from Antelope substation to Rigby substation with at least 1272 ACSR conductor. The un-scoped estimate for this alternative was $48.7 million. Planning studies showed that this alternative line would cause thermal overload and low voltage issues in the area and load shedding and radialization of the Rigby-Sugarmill area would still be required. Due to this and the increased cost for construction this alternative was determined to not be a feasible project to improve service to the Rigby-Sugarmill area.

V. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission determine that the transmission projects outlined in my testimony were necessary to ensure the Company maintains compliance with required reliability standards, to serve increased load, will provide benefits to the Company's customers, and are therefore prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RAV-1)
Docket No. 20-035-04
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

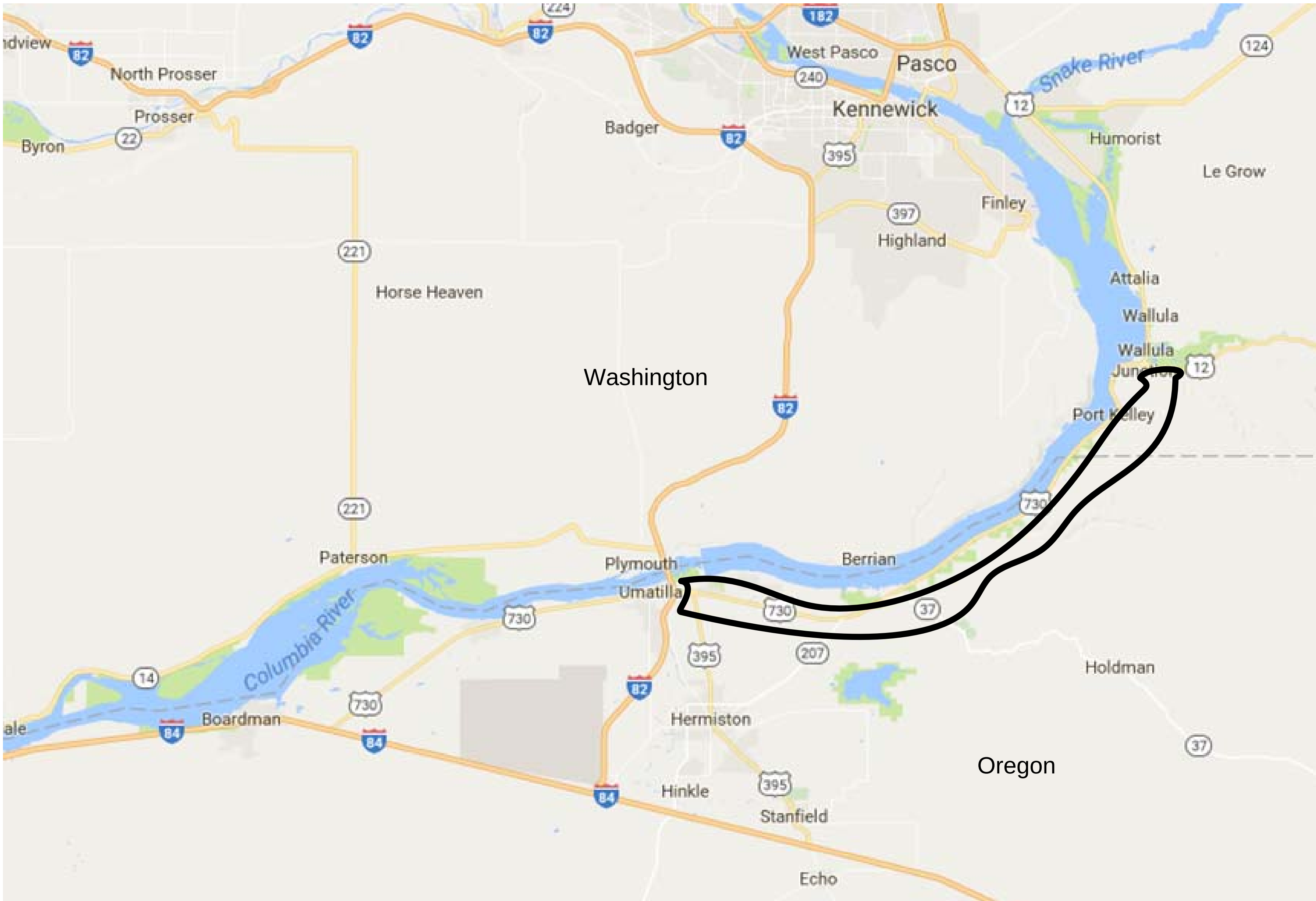
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick A. Vail

Wallula-McNary 230 kV Transmission Project

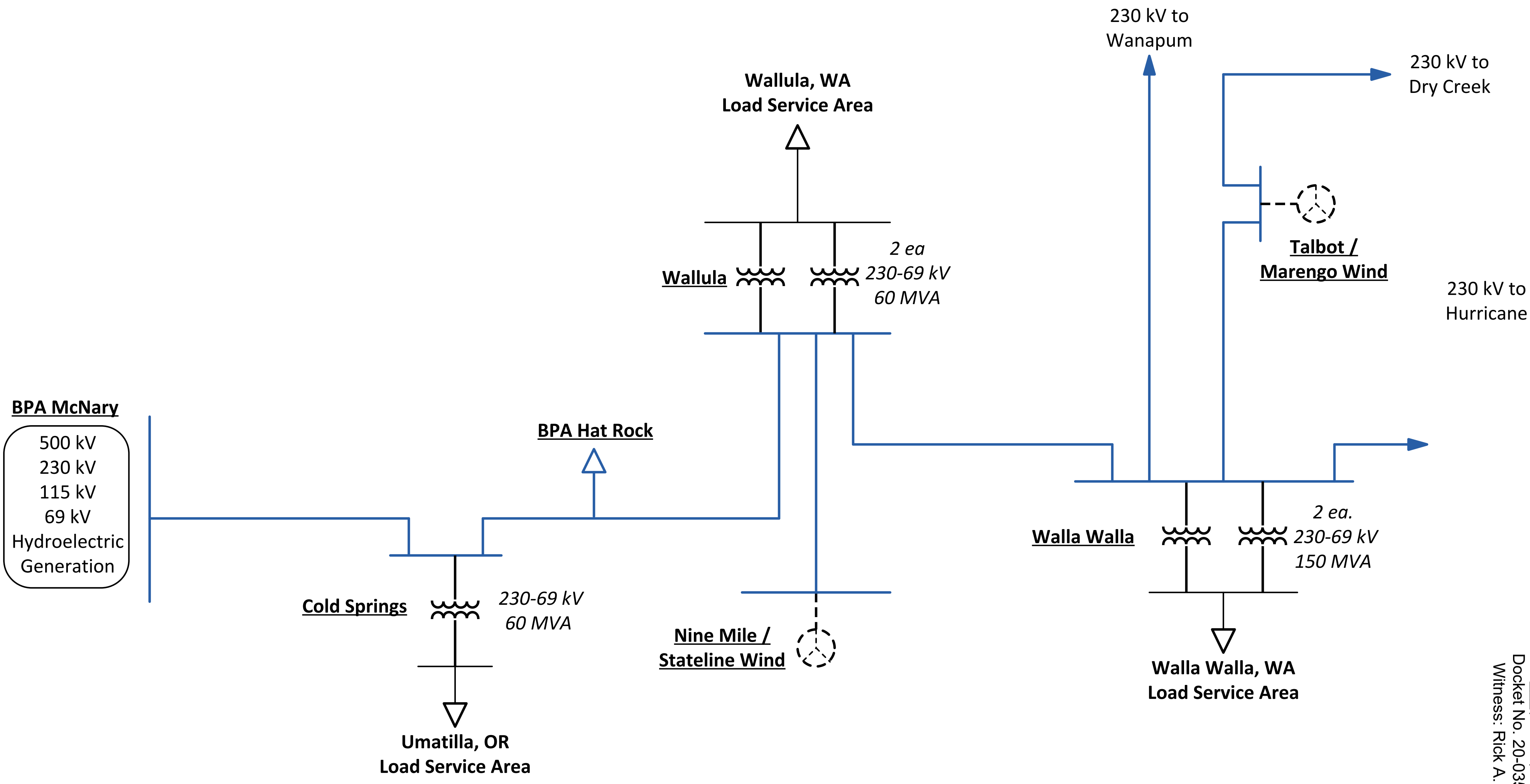
May 2020

Wallula to McNary
230 KV New Transmission Line Project Area



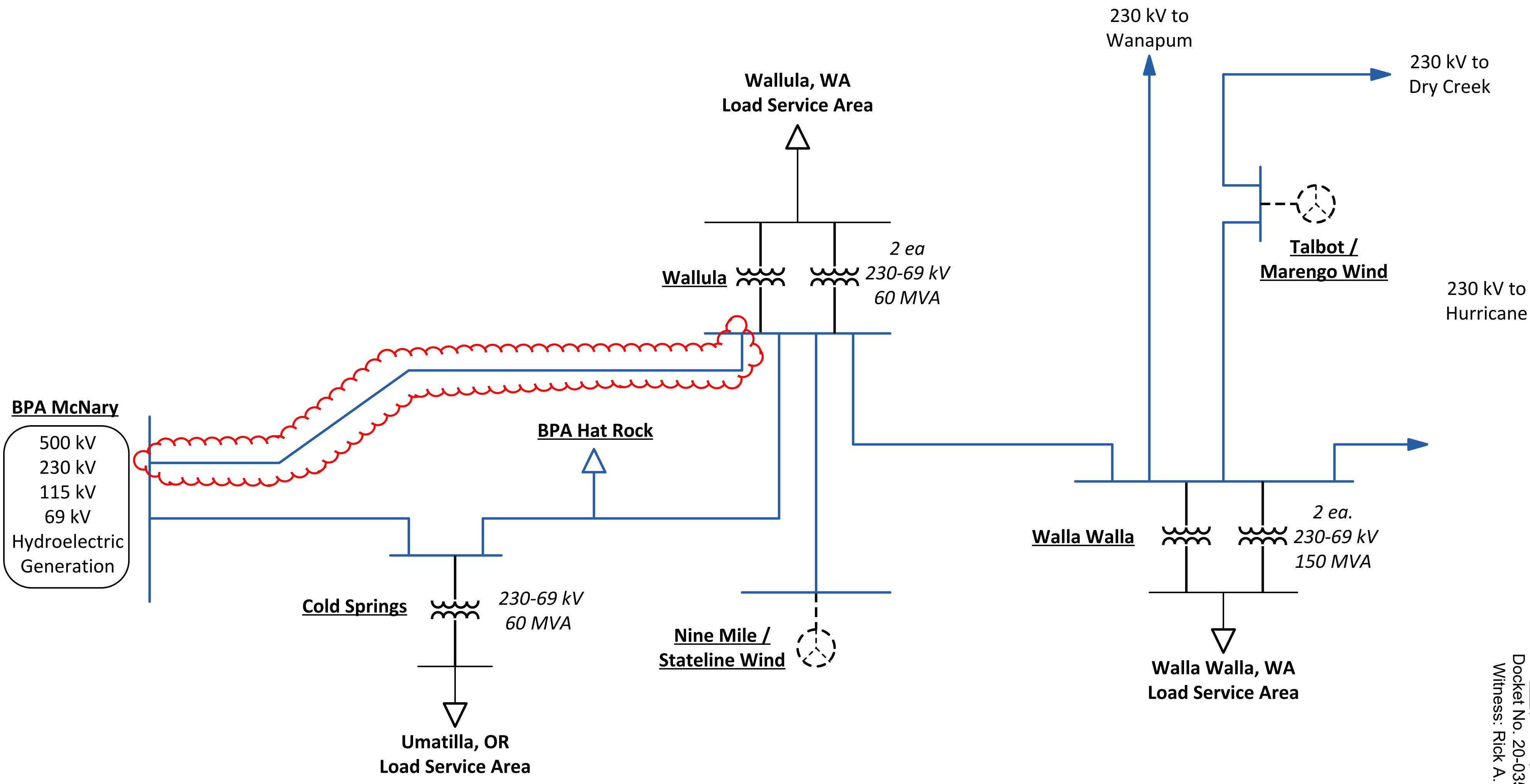
Wallula-McNary #2 Project Diagram
Pre-Project

Note: Dashes Indicate Non-PacifiCorp Facilities



Wallula-McNary #2 Project Diagram
Post-Project

Note: Dashes Indicate Non-PacifiCorp Facilities



Rocky Mountain Power
Exhibit RMP___(RAV-2)
Docket No. 20-035-04
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

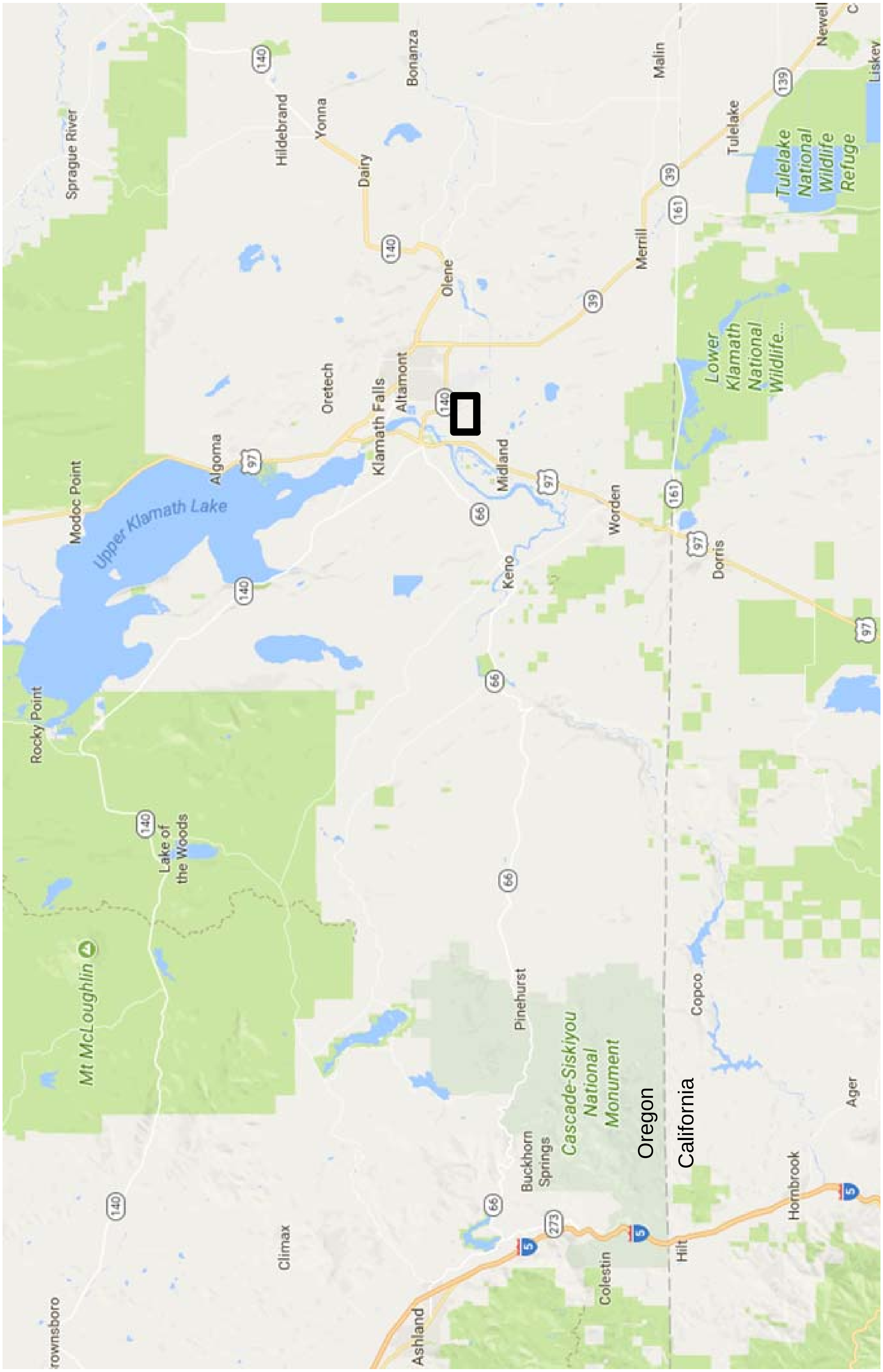
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick A. Vail

Snow Goose Substation Project

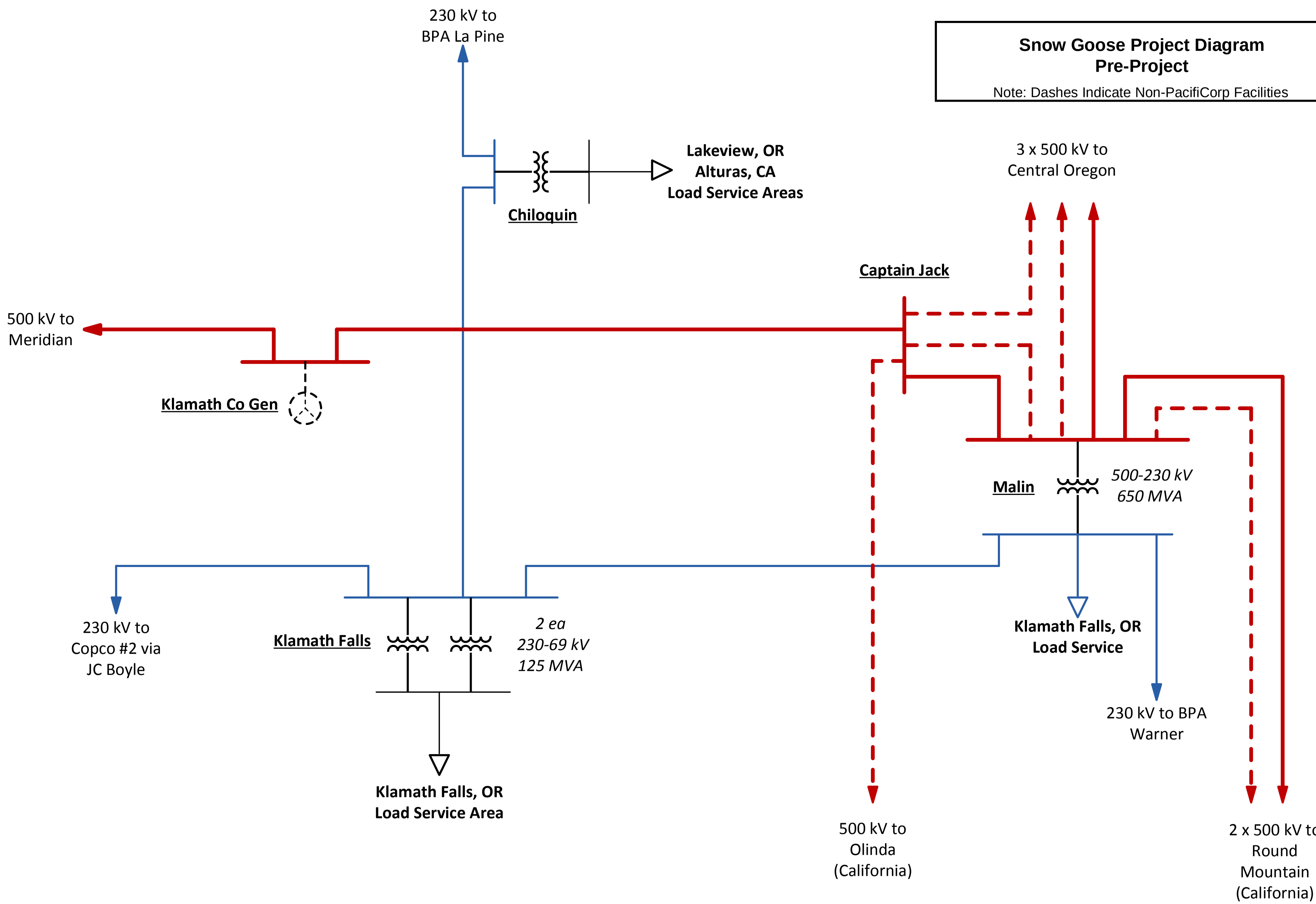
May 2020

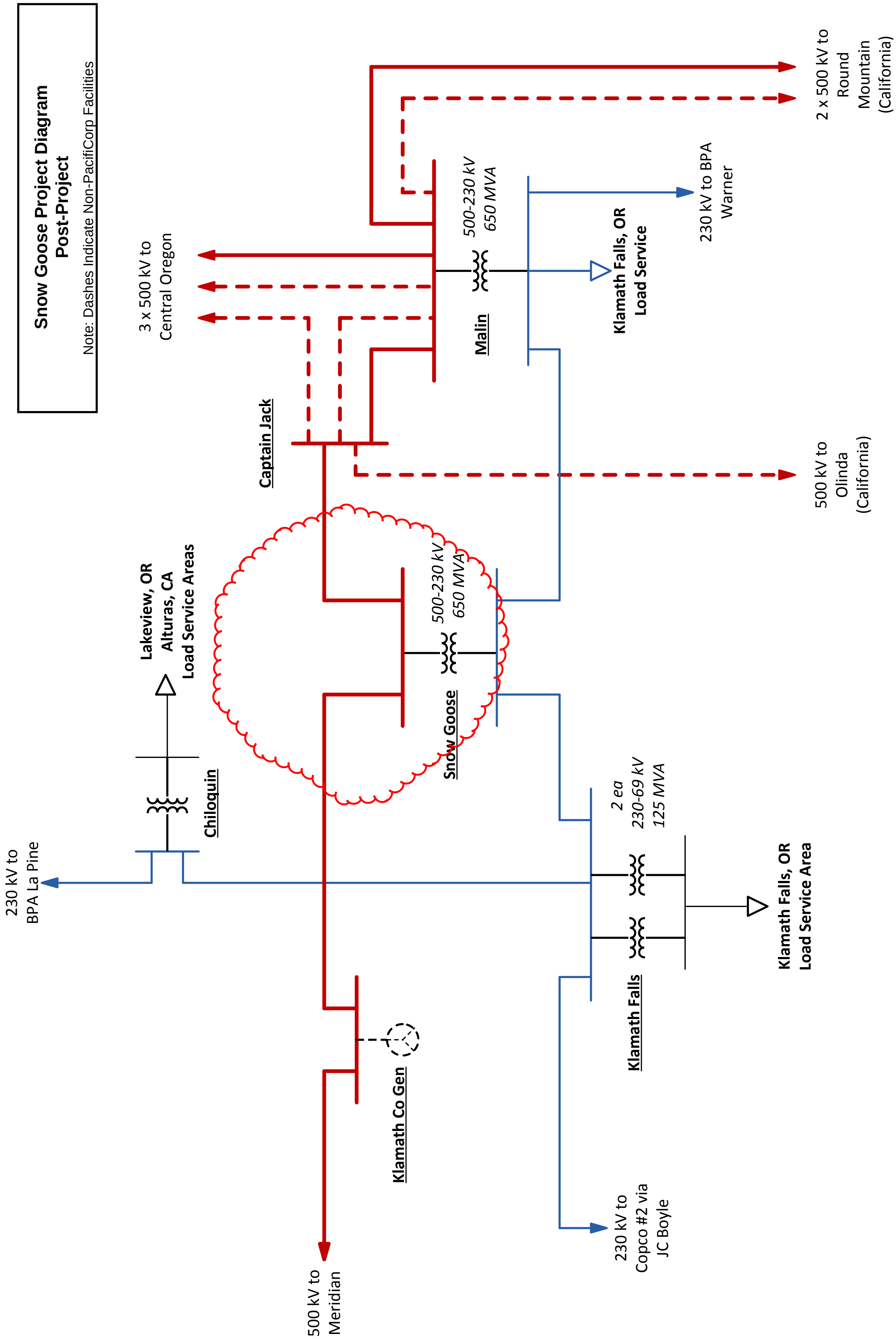
Snow Goose 500-230 KV New Substation Project Area



Snow Goose Project Diagram
Pre-Project

Note: Dashes Indicate Non-PacifiCorp Facilities




Snow Goose Project Diagram
Post-Project
Note: Dashes Indicate Non-PacifiCorp Facilities
3 x 500 kV to Central Oregon
2 x 500 kV to Round Mountain (California)
230 kV to BPA Warner
500-230 kV 650 MVA
Malin
Klamath Falls, OR Load Service
Captain Jack
500 kV to Olinda (California)
Lakeview, OR Alturas, CA Load Service Areas
500-230 kV 650 MVA
Snow Goose
Chiloquin
230 kV to BPA La Pine
2 ea 230-69 kV 125 MVA
Klamath Falls
Klamath Falls, OR Load Service Area
Klamath Co Gen
500 kV to Meridian
230 kV to Copco #2 via JC Boyle

Rocky Mountain Power
Exhibit RMP___(RAV-3)
Docket No. 20-035-04
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

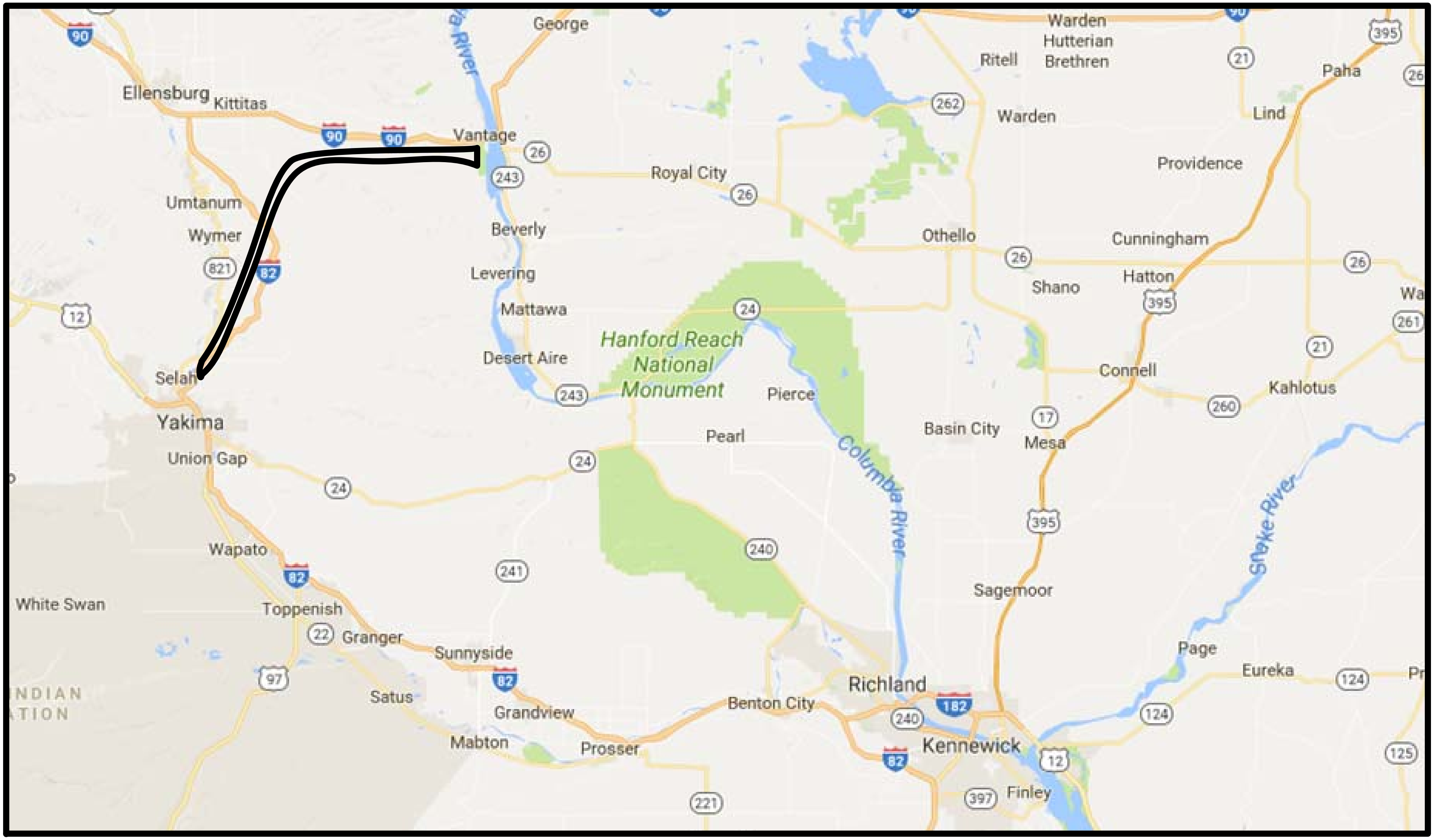
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick A. Vail

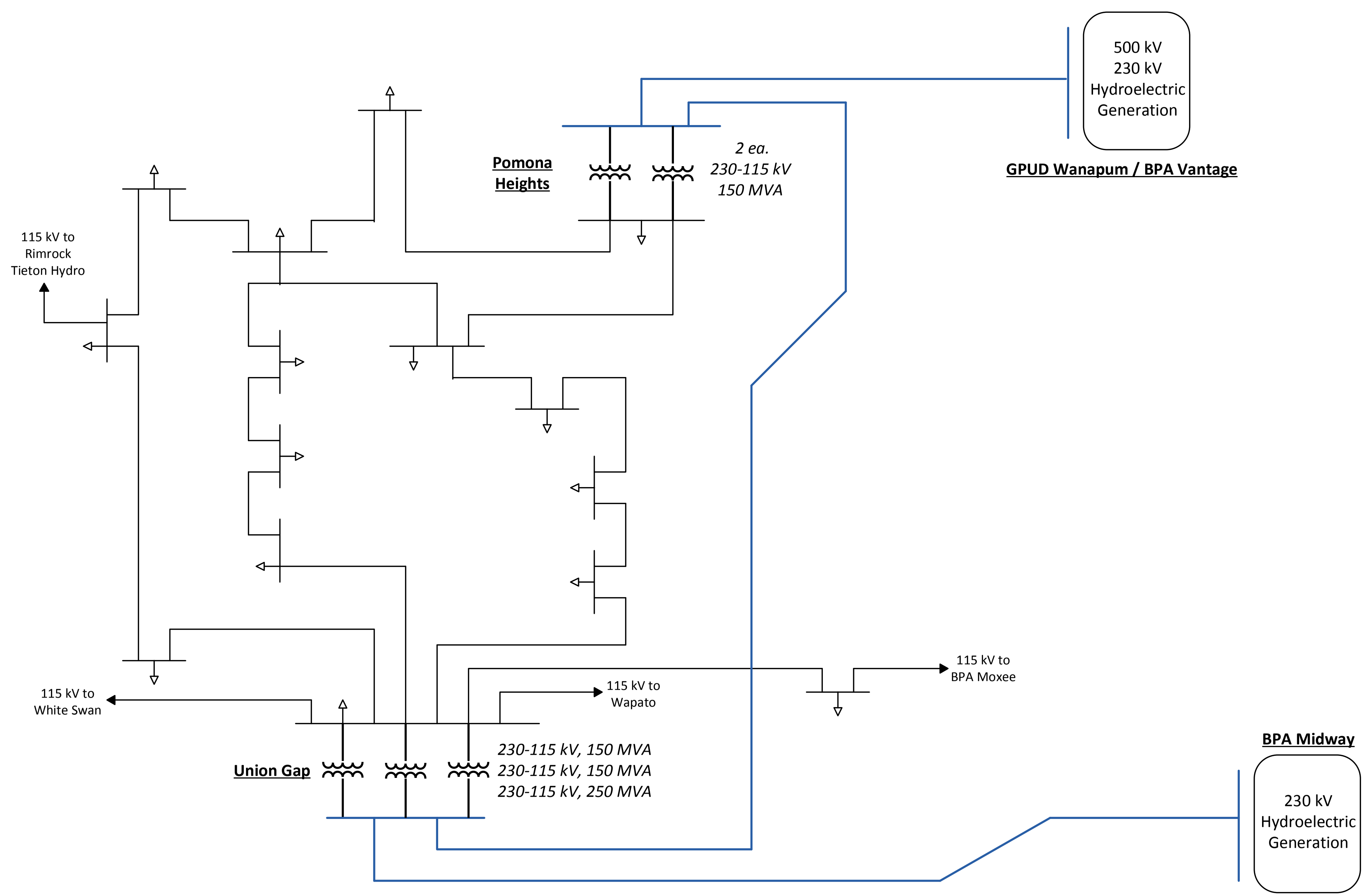
Vantage-Pomona Project

May 2020

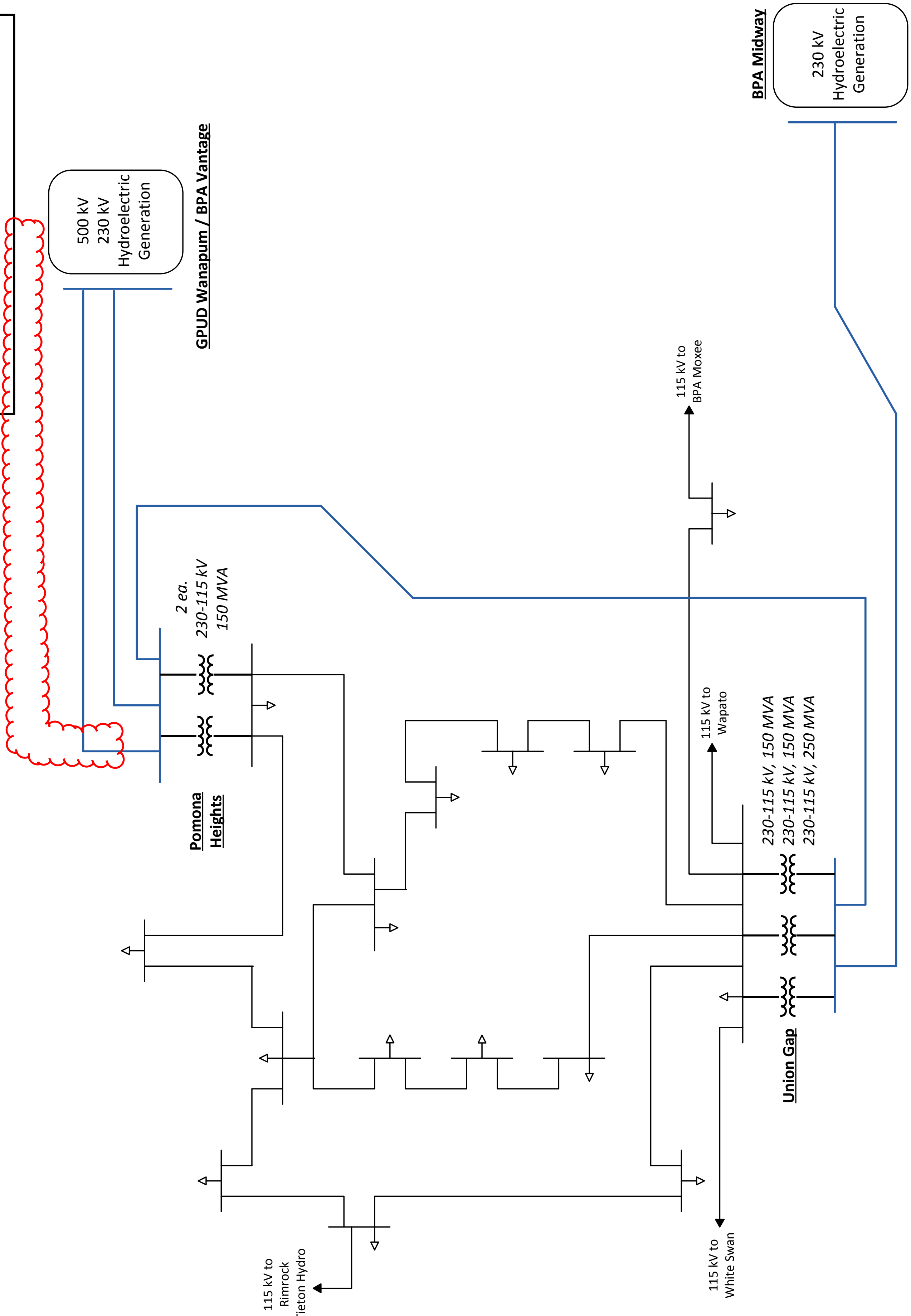
Vantage to Pomona Heights
230 KV New Transmission Line Project Area



Vantage to Pomona Heights Project Diagram
Pre-Project



Vantage to Pomona Heights Project Diagram
Post-Project



Rocky Mountain Power
Exhibit RMP___(RAV-4)
Docket No. 20-035-04
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

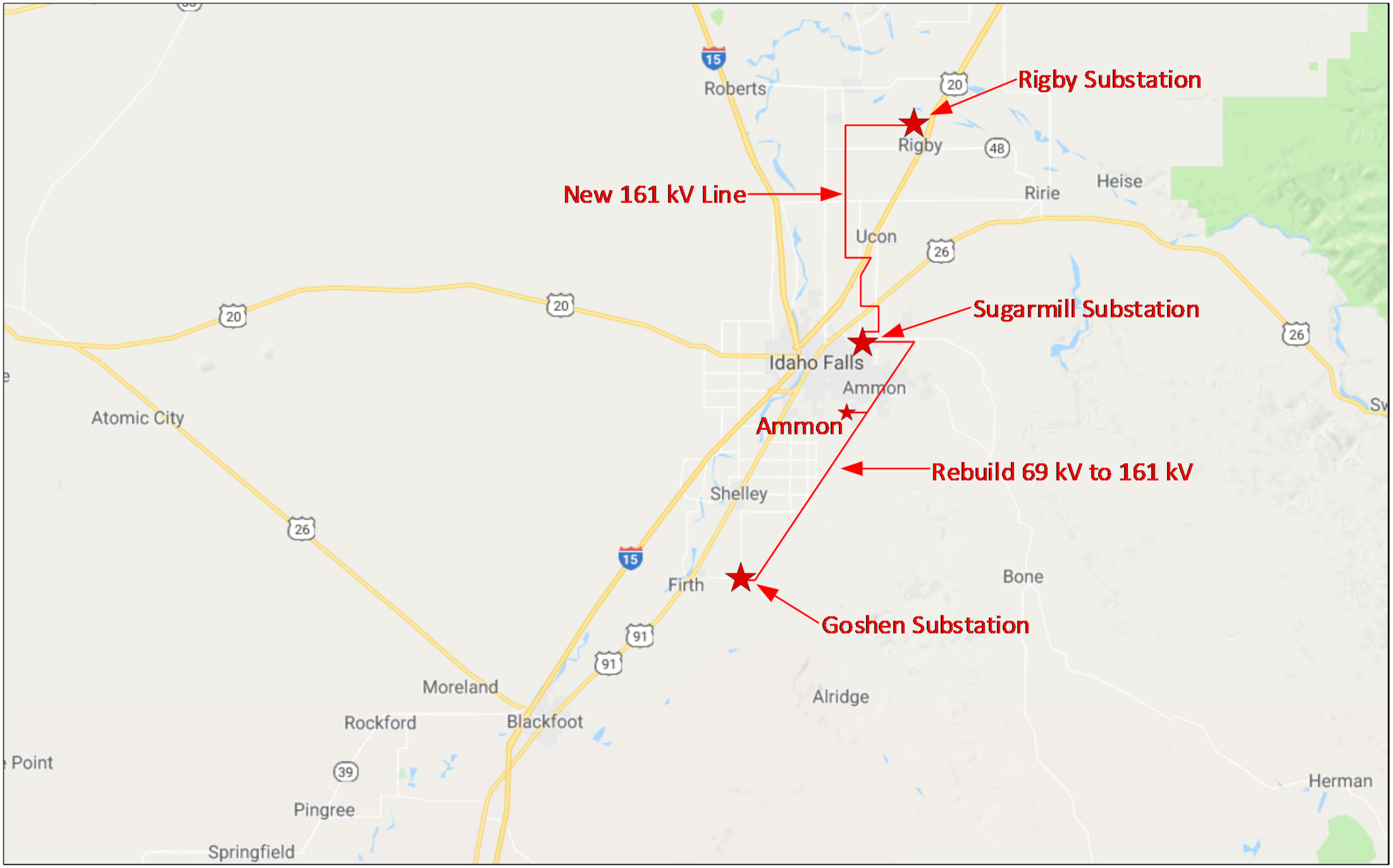
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick A. Vail

Goshen-Sugarmill-Rigby Project

May 2020

Goshen-Sugarmill-Rigby
161 KV Transmission Line Project Area



Rocky Mountain Power
Exhibit RMP___(RAV-5)
Docket No. 20-035-04
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

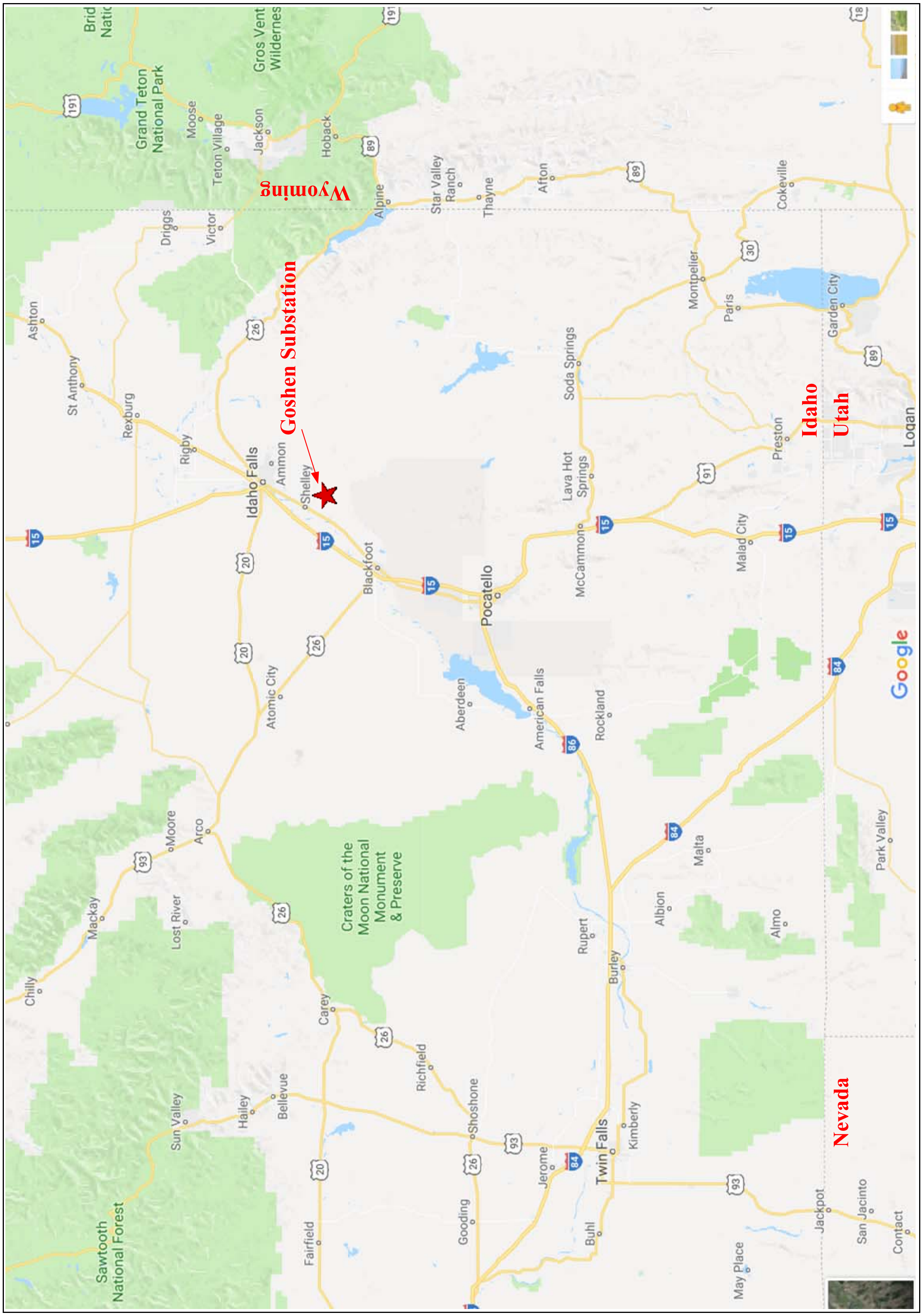
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick A. Vail

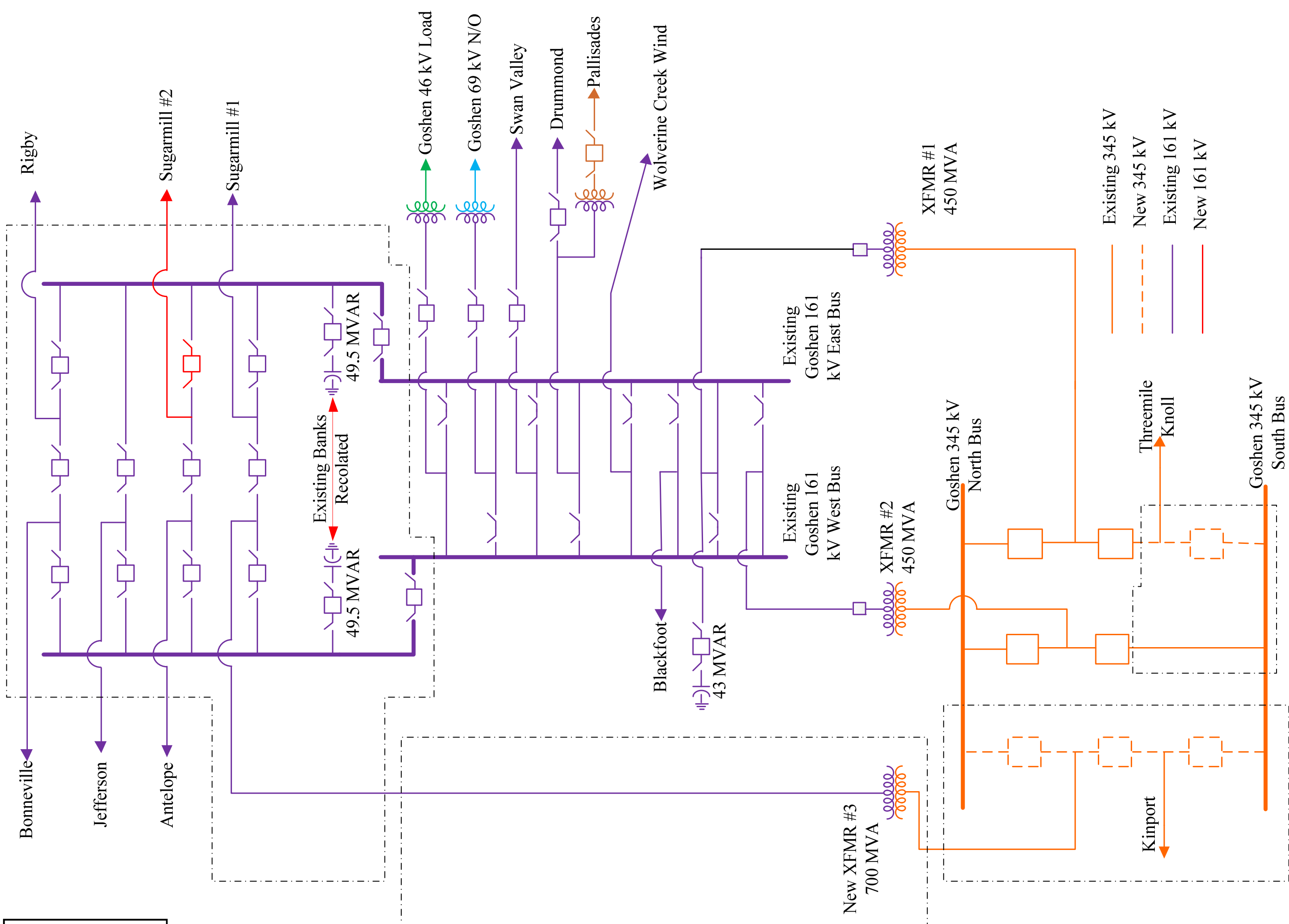
Goshen #3 Project

May 2020

Goshen #3 345/161 kV 700 MVA Transformer Installation Project Area



Rocky Mountain Power
Exhibit RMP___(RAV-5) 2 of 2
Docket No. 20-035-04
Witness: Rick A. Vail



Goshen 345/161 kV Transformer Installation One-line