ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 West North Temple
Salt Lake City, Utah 84116

October 7, 2021

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

Re: Docket No. 21-035-54
Rocky Mountain Power's Application for a Certificate of Public Convenience and Necessity for the Gateway South Transmission Project

Rocky Mountain Power hereby submits for filing its Application for Certificate of Public Convenience and Necessity for the Gateway South Transmission Project. Enclosed are the confidential and non-confidential electronic copies of the testimony, exhibits, and workpapers in the file formats in which they were created.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
jana.saba@pacificorp.com
john.hutchings@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward

Vice President, Regulation

cc: Service List

Richard Garlish
John Hutchings
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone: (801) 220-2533
Facsimile: (801) 220-3299
Email: richard.garlish@pacificorp.com
john.hutchings@pacificorp.com

Katherine McDowell (pro hac vice pending)
Adam Lowney (pro hac vice pending)
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205
Telephone: (503) 595-3924
Facsimile: (503) 595-3928
Email: katherine@mrg-law.com
adam@mrg-law.com

Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE GATEWAY SOUTH TRANSMISSION PROJECT	))))))	Docket No. 21-035-54

PacifiCorp, d/b/a Rocky Mountain Power (the "Company"), in accordance with Utah Code Ann. § 54-4-25, respectfully submits this Application to the Public Service Commission of Utah ("Commission") requesting an order granting a certificate of public convenience and necessity ("CPCN") to construct the 416-mile Gateway South 500-kilovolt ("kV") transmission line. Approximately one-third of the line, or 183 miles, is in Utah, with the balance located in Colorado and Wyoming.

Gateway South is Segment F of the Energy Gateway Transmission Expansion Project ("Energy Gateway"), which has long been recognized as a least-cost, least-risk transmission expansion plan for PacifiCorp, Utah, and the region. Since 2008, the Commission has granted CPCNs or approved resource decisions for the Populus-Terminal transmission line, the Mona-Oquirrh transmission line, the Sigurd-Red Butte transmission line, and the Aeolus-Bridger/Anticline transmission line—all of which are integral components of Energy Gateway.[1] The Company is moving forward with Gateway South as the next Energy Gateway development because current circumstances make it both necessary and economic.

First, PacifiCorp is obligated under its Open Access Transmission Tariff ("OATT") to reliably accommodate nearly 2,500 megawatts ("MW") of interconnection and transmission service requests governed by 13 executed contracts that require the construction of Gateway South. The Company must provide reliable transmission and interconnection service in accordance with the rates, terms, and conditions of PacifiCorp's OATT, which is subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Where a request for OATT service cannot be reliably provided on the existing system, the Company's

[1] *See In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Populus-to-Terminal 345 kV Transmission Line Project*, Docket No. 08-035-42, Report and Order Granting Certificate of Public Need and Necessity (Sept. 4, 2008) (hereinafter "Populus-Terminal CPCN Order"); *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Mona-Oquirrh 500/345 kV Transmission Line*, Docket No. 09-035-56, Report and Order (June 16, 2010) (hereinafter "Mona-Oquirrh CPCN Order"); *In the Matter of Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Sigurd – Red Butte No. 2 345 kV Transmission Line*, Docket No. 12-035-97, Report and Order (March 15, 2013); *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 22 (June 22, 2018) (hereinafter "EV 2020 Order").

OATT and long-standing FERC precedent explicitly require it to construct and expand its system to provide FERC-jurisdictional transmission and interconnection service.[2]

Second, Gateway South will improve grid reliability by providing better operational control of the backbone transmission system by interconnecting two areas of the PacifiCorp transmission system that are abundant in two different forms of renewable resources—wind-rich eastern Wyoming with the solar-rich area of southern Utah. Gateway South also provides critical voltage support to the Company's transmission network and enhances the Company's ability to comply with mandated reliability and performance standards.

Third, the Company's 2021 Integrated Resource Plan ("IRP") demonstrates the need for additional transmission and generation resources to serve load. Gateway South, together with the Gateway West Segment D.1 230-kV transmission line ("Gateway West Segment D.1") (collectively with Gateway South, the "Transmission Projects"), allow the interconnection of over 1,600 MW of new tax-credit-eligible wind resources in eastern Wyoming that were selected in the Company's 2020 All Source Request for Proposals ("2020AS RFP"). The time-limited federal tax incentives from these new renewable generation resources substantially offset the costs of the Transmission Projects.

The Transmission Projects, and the new generation resources they enable, serve the public interest by providing net benefits to customers in a wide range of price-policy scenarios.

[2] *See* PacifiCorp OATT, Sections 28.2 and 15.4 (reflecting verbatim FERC's pro forma tariff established in 1996 and requiring a transmission provider to construct facilities as necessary to reliably provide requested transmission service); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at 767 (2003) (explaining that FERC's pro forma interconnection services "provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 at 814 (2007) (explaining that despite certain policy reforms, transmission providers "will continue to be obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity").

This includes present value revenue requirement differential ("PVRR(d)") customer benefits of $128 million in the base case (assuming medium natural gas and medium carbon dioxide ("CO_2") prices). On a risk-adjusted basis, construction of the Transmission Projects is $260 million lower cost when compared to a portfolio without the Transmission Projects.

The Company plans to construct and energize the Transmission Projects by the end of 2024, requiring construction to begin by June 2, 2022. The Company is on track to have all Utah siting permits by June 2022. Therefore, the Company requests that the Commission grant the requested CPCN for Gateway South no later than June 1, 2022.

I. NAME AND ADDRESS OF APPLICANT

1. PacifiCorp provides retail electric service under the name Rocky Mountain Power in the states of Utah, Wyoming, and Idaho, and under the name Pacific Power in the states of Oregon, Washington, and California. Rocky Mountain Power is a public utility in the state of Utah subject to the jurisdiction of the Commission as to its electric service to retail customers in Utah. Rocky Mountain Power's principal place of business in Utah is 1407 West North Temple, Salt Lake City, Utah 84116.

2. Formal correspondence and requests for additional information regarding this matter should be addressed to:

By email (preferred): datarequest@pacificorp.com

By regular mail:

Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

With copies to:

Jana Saba
Utah Regulatory Affairs Manager
Rocky Mountain Power
Email: jana.saba@pacificorp.com

Richard Garlish
John Hutchings
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Email: john.hutchings@pacificorp.com
richard.garlish@pacificorp.com

Katherine McDowell
Adam Lowney
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205
E-mail: katherine@mrg-law.com
adam@mrg-law.com

Informal inquiries related to this Application should be directed to Jana Saba at (801) 220-2823.

II. SUPPORTING TESTIMONY

3. Rocky Mountain Power's Application for a CPCN for Gateway South is supported by pre-filed written direct testimony and exhibits of the following Company witnesses:

- **Mr. Rick A. Vail,** Vice President of Transmission, provides a detailed description of Gateway South, demonstrates that Gateway South is necessary to both meet the Company's obligations as a transmission provider and improve the reliability of its transmission system. Mr. Vail also describes how the Transmission Projects will increase both the interconnection capacity in eastern Wyoming and the transfer capability out of eastern Wyoming and into central Utah. Mr. Vail explains that PacifiCorp followed the mandatory OATT study process to identify the construction of the Transmission Projects as a prerequisite to reliably providing service in response to nearly 2,500 MW of transmission and interconnection service requests, and then listed the Transmission Projects in multiple FERC-jurisdictional executed contracts accordingly. Mr. Vail also addresses the status of the permitting for Gateway South.

- **Mr. Rick T. Link,** Senior Vice President of Resource Planning, Procurement and Optimization, provides the economic analysis demonstrating that Gateway South is beneficial to Utah customers and in the public interest. Mr. Link describes the customer benefits resulting from the timely construction of the Transmission Projects and explains the need for the Transmission Projects and associated generation resources as outlined in the Company's 2021 IRP. Mr. Link also explains the status of the Company's 2020AS RFP, soliciting cost-effective generation projects enabled by the Transmission Projects, and addresses questions the Commission raised in the 2019 IRP regarding Gateway South.

III. OVERVIEW OF THE TRANSMISSION PROJECTS

A. Description of Transmission Projects.

1. Gateway South

4. Gateway South is a 416-mile, high-voltage 500-kV transmission line that will connect southeastern Wyoming to northern Utah. Gateway South will begin at the Aeolus substation, which is located near Medicine Bow, Wyoming and was recently constructed as part of the Aeolus-to-Bridger/Anticline transmission project. From the Aeolus substation, the line extends west to Wamsutter, Wyoming, and then generally south to the Colorado border.

From there, the line crosses through the northwest corner of Colorado, enters Utah, eventually terminating at the Clover substation near Mona, Utah.

5. Gateway South also requires the Company to modify the existing 345-kV transmission infrastructure in the Mona/Clover area.

6. Because of the length of Gateway South, the Company will construct two series compensation substations along the line to reduce net transmission line impedance and improve the power transfer capability of the line. The addition of series compensation substations also improves power flow control, voltage regulation and increases the transient stability margin of the line.

7. Construction of Gateway South will also require modifications to the Aeolus, Anticline, Clover, and Mona substations to accommodate the new line.

8. The estimated cost of Gateway South is $2.074 billion.

2. Gateway West Segment D.1

9. The Company is not requesting a CPCN for Gateway West Segment D.1, which is located entirely in Wyoming. However, the Company includes the following description of Gateway West Segment D.1 because, together with Gateway South, it is necessary to the interconnection of the majority of the over 1,600 MW of new wind resources in eastern Wyoming selected in the 2020AS RFP. Therefore, the Company's economic analysis described in Mr. Link's testimony, which was derived from the 2021 IRP, appropriately includes the costs and benefits of Gateway West Segment D.1.

10. Gateway West Segment D.1 includes construction of a new 59-mile, high-voltage 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. In addition, the Company will rebuild the

existing Dave Johnston – Amasa – Difficulty – Shirley Basin 230-kV transmission line, which runs approximately 57 miles from the Shirley Basin substation to the Dave Johnston substation near Glenrock, Wyoming.

11. Gateway West Segment D.1 requires construction of a new 230-kV Heward substation that will be sited adjacent to the Difficulty substation, which is owned by Tri-State Generation & Transmission. Gateway West Segment D.1 also requires additions to the Shirley Basin, Dave Johnston, Windstar, and Anticline substations.

12. The estimated cost of the Transmission Projects is $2.4 billion.

IV. LEGAL STANDARD

13. Before constructing a transmission line located in Utah, Utah Code Ann. § 54-4-25 requires that a public utility obtain a CPCN. The statute identifies the "minimum amount and type of evidence" that must be provided,[3] including evidence that: (1) the "present or future public convenience and necessity does or will require the construction" of the line;[4] (2) the "applicant has received or is in the process of obtaining the required consent, franchise, or permit of the proper county, city, municipal, or other public authority";[5] (3) and the line "will not conflict with or adversely affect the operations of any existing certificated fixed public utility which supplies the same product or service to the public and that it will not constitute an extension into the territory certificated to the existing fixed public utility."[6] The Commission has repeatedly affirmed that the CPCN process "is not about the location or siting" of the transmission line.[7]

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[3] Populus-Terminal CPCN Order at 4.
[4] Utah Code Ann. § 54-4-25(1).
[5] Utah Code Ann. § 54-4-25(4)(a)(i).
[6] Utah Code Ann. § 54-4-25(4)(b).
[7] *See, e.g.,* Populus-Terminal CPCN Order at 2.

14. After a decade of planning, the Company now proposes to move forward with construction of Gateway South and place it into service by the end of 2024. Gateway South is an important component of Energy Gateway, and Gateway South has long been recognized as a key transmission segment in the region's long-term transmission planning. By acting now on this time-limited opportunity to develop the Transmission Projects, the Company can provide substantial customer benefits.

15. PacifiCorp followed the OATT process to identify the construction of the Transmission Projects as a prerequisite to reliably providing service in response to nearly 2,500 MW of transmission and interconnection service requests, and the Transmission Projects were listed in multiple FERC-jurisdictional executed contracts accordingly. More specifically, PacifiCorp executed 13 contracts with third-party customers that require construction of one or both of the Transmission Projects, including a transmission service agreement that requires construction of Gateway South to reliably provide 500 MW of firm point-to-point ("PTP") transmission. The Transmission Projects are therefore lynchpins in PacifiCorp's ability to meet its obligation to grant generator interconnection service and transmission service under the OATT.

16. The Transmission Projects, and Gateway South in particular, will also enhance the Company's ability to comply with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards. Congestion on the current transmission system in eastern Wyoming limits the ability to deliver energy from eastern Wyoming to PacifiCorp load centers in Utah, Wyoming, Idaho, and the Pacific Northwest. The Transmission Projects will increase transfer capability by approximately 875 MW from the Windstar/Dave Johnston area south to

Shirley Basin/Aeolus, which, in turn, will support approximately 1,700 MW of incremental transfer capability from eastern Wyoming to the central Utah energy hub.

17. Construction of the Transmission Projects will enable the Company to more efficiently utilize existing generation resources in Wyoming to serve loads in Utah, Wyoming, Idaho, and the Pacific Northwest. The Transmission Projects also better position the Company to interconnect and integrate future resources in southeastern Wyoming and more efficiently serve expected customer load. In addition to increasing the transmission capacity out of eastern Wyoming, the Transmission Projects will also provide critical voltage support to the Wyoming transmission network and enhance the overall reliability of the transmission system by adding incremental new transmission capacity between the Company's existing thermal and renewable facilities and future facilities and other sources of energy in northern Utah. Additional transmission paths will mitigate the impact of outages on the existing system.

18. The Company needs additional resources to serve load and the Transmission Projects enable new, cost-effective wind resources to fill this need. Specifically, the Transmission Projects allow the Company to interconnect up to approximately 2,030 MW of new resources, including over 1,600 MW of new tax-credit-eligible wind resources selected in the 2020AS RFP. As with the Aeolus-to-Bridger/Anticline line, for which the Commission granted resource approval in 2018,[8] the tax credits from new renewable generation enabled by the Transmission Projects produce significant benefits that offset costs of the Transmission Projects.

19. The Company has requested CPCNs from the Wyoming Public Service Commission for the Transmission Projects in Docket No. 20000-588-EN-20 (Record No.

[8] EV 2020 Order.

15604). A hearing in that filing is scheduled for February 22, 2022-March 2, 2022. A CPCN is not required from the Colorado Public Service Commission.

A. Gateway South is Necessary.

1. The Transmission Projects Fulfill the Company's Obligations under its OATT and Avoid Construction of Less Cost-Effective, Stop-Gap Options.

20. The Company is required to provide reliable transmission and interconnection service in accordance with the rates, terms, and conditions of PacifiCorp's FERC-jurisdictional OATT. Where a request for OATT service cannot be reliably provided on the existing system, the Company's OATT and long-standing FERC policy explicitly require it to construct and expand its system to provide FERC-jurisdictional transmission and interconnection service.[9]

21. The OATT's PTP transmission service provisions require a transmission provider to "use due diligence to *expand or modify its Transmission System* to provide the requested Firm Transmission Service" if the transmission provider cannot accommodate the request because of insufficient capability on its system.[10] PacifiCorp's OATT explains that if the transmission system cannot provide firm PTP transmission service without degrading reliability to existing customers or interfering with PacifiCorp's ability to meet its prior

[9] *See* PacifiCorp OATT, Sections 28.2 and 15.4 (reflecting verbatim FERC's pro forma tariff established in 1996 and requiring a transmission provider to construct facilities as necessary to reliably provide requested transmission service); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at 767 (2003) (explaining that FERC's pro forma interconnection services "provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 at 814 (2007) (explaining that despite certain policy reforms, transmission providers "will continue to be obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity").

[10] PacifiCorp OATT, Section 15.4 (emphasis added).

contractual obligations, then PacifiCorp is "*obligated to expand or upgrade its Transmission System*[.]"[11]

22. For interconnection service, FERC requires PacifiCorp to "*construct[] Network Upgrades*" if necessary to allow the interconnecting generator to flow its output onto the transmission system in a safe and reliable manner.[12]

23. The obligation to construct transmission facilities in response to transmission or interconnection service requests applies to both newly identified facilities and planned system expansions or upgrades, like the Transmission Projects, when service requests depend on their construction.[13] PacifiCorp's FERC-approved Attachment K to the OATT makes clear that once a planned transmission project is required to be in service for PacifiCorp to grant an OATT request for PTP transmission service or generator interconnection service, PacifiCorp is obligated to construct the project.[14] Under those circumstances, the OATT requires PacifiCorp to identify the requisite upgrades as "Contingent Facilities" in the OATT studies posted to its Open Access Same-Time Information System ("OASIS") website and ultimately in the FERC-jurisdictional agreement on file with FERC. The Company has executed 13 transmission service and generator interconnection service contracts that list either one or both Transmission Projects as Contingent Facilities. This means that PacifiCorp *cannot provide* the

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[11] PacifiCorp OATT, Section 13.5 (emphasis added).
[12] Order No. 2003 at P 767 (emphasis added).
[13] *California Indep. System Operator*, 133 FERC ¶ 61,224 (2010) (clarifying that the OATT's obligation to construct attaches to planned facilities identified as necessary to grant interconnection requests, stating that "[t]he fact that CAISO has voluntarily chosen to evaluate a network upgrade in its transmission planning process should not affect the obligation to build these facilities.").
[14] PacifiCorp OATT, Attachment K ("Transmission Provider shall use Point-to-Point Transmission Service usage forecasts and Demand Resources forecasts to determine system usage trends, and such forecasts do not obligate the Transmission Provider to construct facilities **until** formal requests for either Point-to-Point Transmission Service or Generator Interconnection Service requests are received pursuant to Parts II and IV of the Tariff.") (emphasis added).

contracted services to 13 contractual counterparties without constructing the Transmission Projects.

24. Among these contracts is an executed 500 MW PTP transmission service agreement that requires Gateway South to be in service. If the Company were not planning to construct Gateway South, the Company's analysis shows that in order to grant only this single PTP transmission service request—and ignoring the other thousands of megawatts of queued service requests—PacifiCorp would be obligated to construct, at a minimum, a 230-kV transmission line at a cost in excess of $1 billion.

25. The Company has also executed 12 interconnection agreements that identify one or both Transmission Projects as Contingent Facilities. Interconnecting these generators without the Transmission Projects would require the Company to construct substantially similar transmission facilities at comparable costs but with fewer financial, interconnection, transmission, and operational efficiencies.

26. The Transmission Projects are cost-effective transmission system upgrades required to allow the Company to meet its OATT obligation to provide transmission and interconnection service. It is unrealistic to assume that, absent the Transmission Projects, the Company would not be obligated to construct *any* transmission system upgrades out of eastern Wyoming to accommodate FERC-jurisdictional requests for OATT interconnection service and transmission service.

2. The Transmission Projects enable the Company to efficiently satisfy its obligation to comply with mandatory reliability standards.

27. The Commission granted a CPCN for Energy Gateway's Populus-Terminal transmission line, in part, because "future utility service will be more reliable and efficient"

with the transmission line.[15] Similarly, when granting a CPCN for Energy Gateway's Mona-Oquirrh transmission line, the Commission relied on evidence that the line would "strengthen [PacifiCorp's] transmission grid in order to comply with important regional and national reliability standard and directives."[16] Like Populus-Terminal, Mona-Oquirrh and Sigurd-Red Butte, the Transmission Projects are a critical component of the Company's short- and long-term plan to meet its federal reliability mandates.

28. NERC's TPL-001-4 standard requires the Company to have a forward-looking transmission plan to reliably serve current and anticipated customer demands under all expected operating conditions, including normal system operations (all system elements in service) and during system contingencies (where multiple elements of the transmission system are out of service), both planned or otherwise. To meet this standard, the Company performs annual reliability assessments to determine whether its transmission system complies with minimum mandatory system performance standards. The Transmission Projects, as part of Energy Gateway, have 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 for eight years. The Transmission Projects' new transmission segments are particularly effective in increasing system reliability under the various multiple contingency categories of the TPL-001-4 standard.

29. The Company could maintain long-term compliance with the TPL-001-4 standard without any new transmission facilities in eastern Wyoming only if the transmission system experienced ***no*** changes in loads or resources—which is an entirely unrealistic assumption.

[15] Populus-Terminal CPCN Order at 3.
[16] Mona-Oquirrh CPCN Order at 15.

3. The Transmission Projects Provide Substantial Customer Benefits.

30. When granting a CPCN for Energy Gateway's Mona-Oquirrh transmission line, the Commission pointed to the Company's 2008 IRP, which identified Energy Gateway generally "as the blueprint to most efficiently integrate transmission lines and collection points with resources and load centers."[17] The Commission also focused on the fact the line and "more broadly Energy Gateway, will increase the Company's system-wide access to new and existing resources."[18] Here, like Mona-Oquirrh, the Transmission Projects are a critical component of Energy Gateway and the Company's economic analysis from the 2021 IRP, presented here in Mr. Link's testimony, demonstrates that construction of the Transmission Projects will provide substantial customer benefits.

31. The Company's 2021 IRP shows that PacifiCorp has a capacity deficit in all years of the 20-year planning horizon. In 2021, the capacity need is over 1,000 MW and increases over time to over 6,600 MW by 2040. In 2025, the first full year that the Transmission Projects will be online, the capacity need is 1,672 MW.

32. To identify the most cost-effective approach to meet the identified capacity need, PacifiCorp utilized its new, more advanced Plexos resource modeling and optimization tool to construct and select the preferred portfolio in the 2021 IRP. When optimizing resource portfolios, the Plexos model is able to view the costs and benefits of certain transmission upgrades and can select specific transmission upgrades that enable new resource additions. The model accounts for costs of potential transmission resources and the value generated by the transmission resources by enabling low-cost generation options and better optimizing how resources are used to serve load to lower system costs.

[17] Mona-Oquirrh CPCN Order at 14.
[18] Mona-Oquirrh CPCN Order at 15.

33. The Plexos model selected the Transmission Projects, and the low-cost generation resources enabled by the Transmission Projects, as critical components of the least-cost, least-risk portfolio of resources to serve customers through the 20-year IRP planning horizon.

34. To individually analyze the Transmission Projects, the Company used Plexos to model its system with and without the Transmission Projects and associated wind resources across multiple natural gas and greenhouse gas price scenarios. This with and without modeling was directly responsive to the Commission's concerns in the 2019 IRP[19] and 2020AS RFP proceeding[20] and consistent with the modeling the Commission found "thorough and extensive" when approving the Energy Vision 2020 resources.[21] When individually analyzed, the Company's modeling demonstrates that through 2040, the resource portfolio that includes the Transmission Projects is $128 million lower cost than the comparable portfolio without the Transmission Projects, when examined using a medium natural gas, medium carbon dioxide price-policy scenario. On a risk-adjusted basis, construction of the Transmission Projects is $260 million lower cost when compared to a portfolio without the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

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[19] *PacifiCorp's 2019 Integrated Resource Plan*, Docket No. 19-035-02, Order at 22 (May 13, 2020) (hereinafter "2019 IRP Order") (Commission concerned that PacifiCorp "did not model the Preferred Portfolio without the yet-to-be-built Gateway South as a presumed component," which was "inadequate" because the 2019 IRP Action Plan called for "nearly immediate construction of the line without identifying and justifying selection of the specific resources that will rely on it and, in particular, their geographic location.").

[20] *Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals*, Docket No. 20-035-05, Order Approving 2020 All Source RFP at 14-15 (July 17, 2020) (Company committed to "perform, at minimum, a sensitivity that removes Gateway South and all bids that require Gateway South" as part of RFP evaluation process, which the Commission found was reasonable and adequately addressed concerns over the impact of the Transmission Projects on RFP bids).

[21] EV 2020 Order at 22.

35. Further, the risk-adjusted results demonstrate that there is a tremendous opportunity cost of not building the Transmission Projects in the likely event that regulatory policies at some point in the future will impose costs on greenhouse gas emissions. Among all scenarios that assume some costs for greenhouse gas emissions, the portfolios with the Transmission Projects are significantly lower cost than portfolios without the Transmission Projects—with customer savings ranging from $128 million to over $2.8 billion.

36. Moreover, without the Transmission Projects, PacifiCorp customers will be exposed to increasing market risk, in the form of both price and volume volatility. Indeed, without the Transmission Projects, and the associated generation enabled by the projects, market purchases increase by nearly 20 percent on an annual basis. This creates higher risk as the Company is forced to rely on market purchases at a time when there are increasing resource adequacy concerns throughout the Western Interconnection. This increased market and reliability risk is not reflected in the PVRR(d) results and provides additional evidence that the potential customer savings are conservative.

37. To further confirm the robust customer benefits resulting from the construction of the Transmission Projects, the Company also modeled potential alternative transmission investments responsive to the Commission's concerns raised in the 2019 IRP and 2020AS RFP proceedings. In particular, the Commission was concerned that PacifiCorp did not model a potential alternative transmission expansion case evaluated by the Northern Tier Transmission Group ("NTTG") in its 2018-2019 Regional Transmission Plan.[22] As explained by Mr. Link, the Company explicitly modeled the NTTG case study for this filing and the results favor construction of the Transmission Projects by a significant margin.

[22] 2019 IRP Order at 22; *see also* Order Approving 2020 All Source RFP at 14-15.

B. The Company Has or Will Obtain the Required Permits.

38. The Company has obtained many of the required permits and will obtain all permits ahead of construction. There are a number of construction related permits that will be the responsibility of the construction contractor to obtain prior to construction. A list of the required permits and status can be found in Exhibit 1 attached to this Application.

C. Construction of Gateway South Will Not Conflict with Any Other Utility's Service.

39. The construction of Gateway South will not conflict with or otherwise adversely impact the provision of electric service by any other utility that is certified to provide electric utility service in Utah. The construction of Gateway South will also not constitute an extension of service into a territory for which another utility has a CPCN to provide electric utility service.

D. The Company has the Financial Ability to Construct Gateway South.

40. The Company intends to finance Gateway South through its normal internal and external sources of capital, including net cash flow from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions, and other sources. The financial impact will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates.

V. CONCLUSION

Rocky Mountain Power respectfully requests that the Commission issue an order on or before June 1, 2022, granting a CPCN to construct Gateway South. Gateway South is prudent and in the public interest and is an integral component of the Company's long-term plans to provide stable, reliable electric service at just and reasonable rates.

Respectfully submitted this 7th day of October, 2021.

Richard Garlish
John Hutchings
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone: (801) 220-2533
Facsimile: (801) 220-3299
Email: richard.garlish@pacificorp.com
Email: john.hutchings@pacificorp.com

Attorneys for Rocky Mountain Power

Exhibit 1

Gateway South - Utah Federal, State, and Local Permits and Approvals

Table 1 is a list of the major federal, state, and local permits and approvals that could be required for construction, operation, and maintenance of the Gateway South Project (the Utah portion only).

TABLE 1 - SUMMARY OF POTENTIAL MAJOR FEDERAL, STATE, AND LOCAL PERMITS OR LICENSES REQUIRED AND OTHER ENVIRONMENTAL REVIEW REQUIREMENTS FOR THE GATEWAY SOUTH PROJECT'S CONSTRUCTION AND OPERATION IN UTAH

Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
FEDERAL					
Locating Facilities on Land under Federal Management					
Preconstruction surveys; construction, operation, maintenance	Bureau of Land Management (BLM)	Right-of-way grant and temporary-use permit (an approved Plan of Development [POD] would be a condition of approval to granting the right-of-way	Federal Land Policy and Management Act (FLPMA) of 1976 (Public Law [P.L.] 94-579+); 43 United States Code (U.S.C.) 1761 et seq.; 43 CFR 2800	PacifiCorp	Received on 1/23/17
Preconstruction surveys; construction, operation, maintenance	U.S. Forest Service (USFS)	Special-use authorization	FLPMA, as amended	PacifiCorp	Received on 1/7/2020
Biological Resources					
Protection of Federally Endangered, Threatened and Listed species via Biological Opinion	U.S. Fish and Wildlife Service (FWS)	Endangered Species Act compliance by consultation with FWS (may require permit for incidental take of listed species)	Endangered Species Act, as amended (16 U.S.C. 1531 et seq.)	PacifiCorp/Construction Contractor	Consultation completed as part of EIS. Construction Contractor to ensure compliance during construction
Protection of migratory birds	FWS	Compliance	Migratory Bird Treaty Act (16 U.S.C. 703 et seq.); 50 CFR 1; individual agency guidance; Memoranda of Understanding between federal land-management agencies and FWS	Construction Contractor	Maintain compliance during construction

TABLE 1 - SUMMARY OF POTENTIAL MAJOR FEDERAL, STATE, AND LOCAL PERMITS OR LICENSES REQUIRED AND OTHER ENVIRONMENTAL REVIEW REQUIREMENTS FOR THE GATEWAY SOUTH PROJECT'S CONSTRUCTION AND OPERATION IN UTAH

Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
Protection of bald and golden eagles	FWS	Compliance (may require permit for take of eagles)	Bald and Golden Eagle Protection Act of 1972 (16 U.S.C. 668), including the Final Eagle Permit Rule, or implementing regulations of September 11, 2009 (50 CFR 13; 50 CFR 22)	PacifiCorp	Will obtain permit if necessary
Protection of special status species	BLM and USFS	Compliance	BLM Policy Manual 6840; agency guidance	Construction Contractor	Maintain compliance during construction
Protection of fish, wildlife, and aquatic resources	BLM and USFS	Compliance	BLM Policy Manuals 6500 and 6720	Construction Contractor	Maintain compliance during construction
Ground Disturbance and Water Quality Degradation					
Construction sites with greater than 1 acre of land disturbed	U.S. Environmental Protection Agency (EPA) (Utah Department of Environmental Quality [UDEQ])	Section 402 National Pollutant Discharge Elimination System General Permit for Storm Water Discharges from Construction Activities	Clean Water Act of 1972 (CWA) (33 U.S.C. 1342)	Construction Contractor	Prior to construction
Crossing 100-year floodplain, streams, and rivers	USACE	Floodplain use permits	40 U.S.C. 961	PacifiCorp	In progress
Discharge of dredge or fill material into waters of the United States, including wetlands	USACE	USACE 404 Permit (individual or coverage under nationwide permit)	CWA (33 U.S.C. 1344)	PacifiCorp	In progress
Placement of structures and construction work in navigable waters of the United States	USACE	Section 10 permit	Rivers and Harbors Act of 1899 (33 U.S.C. 403)	PacifiCorp	In progress

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Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
Potential pollutant discharge during construction, operation, and maintenance	EPA	Spill Prevention Control and Countermeasure Plan for substations	Oil Pollution Act of 1990 (40 CFR 112)	Construction Contractor	Prior to construction
Cultural Resources					
Disturbance of historic properties	Federal lead agency, State Historic Preservation Office (SHPO), Advisory Council on Historic Preservation	Section 106 consultation	National Historic Preservation Act of 1966 (54 U.S.C. 306108; 36 CFR 800)	PacifiCorp/Construction Contractor	Consultation completed as part of EIS. Construction Contractor to ensure compliance during construction
Excavation of archaeological resources	Federal land-management agency	Permits to excavate	Archaeological Resources Protection Act (ARPA) of 1979 (16 U.S.C. 470aa to 470ee)	PacifiCorp	Would acquire, if needed
Potential conflicts with freedom to practice traditional American Indian religions	Federal lead agency, federal land-management agency	Consultation with affected American Indians	American Indian Religious Freedom Act of 1978 (42 U.S.C. 1996)	PacifiCorp	Complete
Disturbance of graves, associated funerary objects, sacred objects, and items of cultural patrimony	Federal land-management agency	Consultation with affected Native American groups regarding treatment of remains and objects	Native American Graves Protection and Repatriation Act of 1990 (25 U.S.C. 3001-3002)	PacifiCorp	Would acquire, if needed
Investigation of cultural resources	Affected land-management agency	Permit for study of historical and archaeological resources	FLPMA of 1976	PacifiCorp	Complete
Paleontological Resources					
Ground disturbance on federal land or federal aid project	BLM and USFS	Compliance with BLM and USFS mitigation and planning standards for paleontological resources of public lands	FLPMA (43 U.S.C. 1701 et seq.); 36 CFR 291; BLM Handbook H-8270; BLM Handbook 8270	PacifiCorp	Complete

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Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
Collection of paleontological resources from federal land	BLM and USFS	Permit to collect paleontological resources from federal land	Omnibus Public Lands Management Act of 2009 – Paleontological Resources Preservation; (P.L. 111-11, Title VI, Subtitle D, Sections 6301 et seq., 123 Stat. 1172); 16 U.S.C. 470aaa	PacifiCorp	Complete
Use of Pesticides					
Use of pesticides or herbicides on federal lands	Federal land-management agencies	Incorporate into right-of-way grant and temporary-use permit (BLM) and special-use authorization (USFS)	Carlson-Foley Act (43 U.S.C. 1241); Federal Noxious Weed Act of 1974 (P.L. 93-629) (76 U.S.C. 2801 et seq.), BLM Manual 9015	PacifiCorp	Complete
Air Traffic					
Location of towers and spans in relation to airport facilities and airspace	Federal Aviation Administration (FAA)	File notice of proposed construction or alteration; FAA to determine if structure is no hazard	FAA Act of 1958 (P.L. 85-726); 14 CFR 77	Construction Contractor	Prior to construction
Transportation					
Use of National Forest System Roads	USFS	Road use permit	Sections 4 and 6, National Forest Roads and Trail Act of 1964; 16 U.S.C. 535 and 537	PacifiCorp	In progress
TRIBAL					
Locating Facilities on Land of Indian Reservations					

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Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
Crossing roads or irrigation facilities on Indian reservation land	BIA	Encroachment permit	25 CFR 169	PacifiCorp	In progress
Grant of easement across Indian reservation	BIA in coordination with Ute Indian Tribe of the Uintah and Ouray Indian Reservation	Grant of Easement	25 CFR 169	PacifiCorp	In progress
Conduct Business					
Conducting business on the Uintah and Ouray Indian Reservation	Ute Indian Tribe of the Uintah and Ouray Indian Reservation	Business license	Requirement of the Ute Tribal Employment Rights Office and Ute Business Council	Construction Contractor	Prior to construction
STATE OF UTAH					
Project Need					
Project construction	PSC	Certificate of Public Convenience and Necessity; approve construction contracts	Utah Code Title 54-4-25 and UAC Title R746-401	PacifiCorp	In progress
State Lands					
Encroachment on, through, or over state land	Utah Division of Forestry, Fire and State Lands (FFSL), Utah School and Institutional Trust Lands Administration (SITLA), and Utah Division of Wildlife Resources (UDWR)	Application approval; easement on state land (bond may be required)	Utah Code Title 65A-7-8 and UAC Title R652 for FFSL; Utah Code Title 53C and UAC Title R850 for SITLA; and Utah Code Title 23 and UAC Title R657 for UDWR	PacifiCorp	In progress
Water					
Construction sites with greater than 1 acre of land disturbed	Utah Division of Water Quality	Stormwater permit	UAC Title R317	Construction Contractor	Prior to construction

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Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
Potential discharge into waters of the state (including wetlands and washes)	UDEQ	Section 401 permit	UAC Title R-317	Construction Contractor	Prior to construction
Air					
Construction and operation	Air Quality Board	Notice of Construction	Utah Code Title 19-2-108 and UAC Title R317	Construction Contractor	Prior to construction
Cultural Resources					
Survey or excavation of archaeological resources on lands owned or controlled by the state	Utah Governor's Public Lands Policy Coordination Office	Permit to survey or excavate	Utah Code Title 9-8-305; UAC Title R694-1	PacifiCorp Construction Contractor	Complete Will obtain, if required
Disturbance of historic properties	SHPO, Utah Division of State History	SHPO will comment on state-funded undertakings	Utah Code Title 9-8-404 and UAC Title R455	Construction Contractor	Will obtain, if required
Discovery of graves, associated funerary objects, sacred objects, and items of cultural patrimony on nonfederal-, nonstate-administered land	Antiquities Section, Utah Division of State History	Consultation with state agency regarding treatment of human remains and funerary objects	Utah Code Title 76-9-704 and 9-9-403 to 9-9-405; UAC Title R203-1 and R455-4	Construction Contractor	Will obtain, if required
Impact on historical sites	Division of State History	Notification of planning stage and before construction	Utah Code Title 9-8-404	Construction Contractor	Will obtain, if required
Paleontological Resources					
Excavation and collection of paleontological resources from state lands	Utah Geological Survey, Utah Museum of Natural History, SITLA	Permit to excavate and collect paleontological resources from state land	Utah Code Title 79-3-501 and 79-3-502; Utah Code Title 63-73-11 through 63-73-19	Construction Contractor	Will obtain, if required
Wildlife					
Modification of habitat	UDWR	Easement for use of state wildlife resource lands	Utah Code Title 23 and UAC Title R657	PacifiCorp	In progress

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Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
Noxious Weeds					
Construction and operation activities	Utah Department of Agriculture and Food	Compliance	Utah Administrative Code (UAC) Title R68-9	Construction Contractor	Maintain compliance during construction
Local					
Construction and operation of transmission lines	Carbon County	Conditional-use permit	The Development Code of Carbon County, Utah – Sections 4.2.10C, 4.2.11C, 4.2.21C, 4.2.13C, 4.2.14C, 4.2.15C, 4.2.17C, 4.2.1C, 4.2.3C, 4.2.2C, 4.2.16C	PacifiCorp	Permit issued 10/23/2020
	Juab County	Conditional-use permit	Juab County Land Use Code 2018	PacifiCorp	Permit issued 10/7/2020
	Sanpete County	Conditional Use Permit	Sanpete County Land Use Ordinance 2020	PacifiCorp	Permit issued 10/14/2020
	Uintah County	Conditional Use Permit	Uintah County Code of Ordinances 2011 – Chapter 17.28.030, 17.0	PacifiCorp	Permit issued 10/14/2020
	Utah County	Conditional Use Permit	Utah County Land Use Ordinance 2010 – Sections 5-5, 5-6, 5-9	PacifiCorp	Permit issued 11/6/2020
	Duchesne County	Permitted Use	Duchesne County Zoning Ordinance Title 8	PacifiCorp	Not required
	Wasatch County	Conditional Use Permit	Wasatch County Land Use and Development Code 2012 – Section 16.05.03, 16.11.02	PacifiCorp	In progress
Road Use, Building Permits, Driveway Permits, etc.	Carbon County	Other permits as required	The Development Code of Carbon County, Utah	Construction Contractor	Will obtain, as required prior to construction

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Action Requiring Permit, Approval, or Review	Agency	Permit, License, Compliance, or Review	Relevant Laws and Regulations	Responsibility	Status
	Juab County	Other permits as required	Juab County Land Use Code 2018	Construction Contractor	Will obtain, as required prior to construction
	Sanpete County	Other permits as required	Sanpete County Land Use Ordinance 2020	Construction Contractor	Will obtain, as required prior to construction
	Uintah County	Other permits as required	Uintah County Code of Ordinances 2011	Construction Contractor	Will obtain, as required prior to construction
	Utah County	Other permits as required	Utah County Land Use Ordinance 2010	Construction Contractor	Will obtain, as required prior to construction
	Duchesne County	Other permits as required	Duchesne County Zoning	Construction Contractor	Will obtain, as required prior to construction
	Wasatch County	Other permits as required	Wasatch County Land Use and Development Code	Construction Contractor	Will obtain, as required prior to construction

REDACTED
Rocky Mountain Power
Docket No. 21-035-54
Witness: Richard A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Richard A. Vail

October 2021

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

A. My name is Rick A. Vail. My business address is 825 NE Multnomah, 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, asset management, capital budgeting for transmission, and administration of the Company's Open Access Transmission Tariff ("OATT"). I am testifying on behalf of PacifiCorp d/b/a Rocky Mountain Power (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 employed at the Company since 2001, and have had a range of management responsibility within the asset management group, including capital planning, maintenance policy, maintenance planning, and investment planning. I served as director of asset management from 2007 to 2012. I became Vice President of Transmission in December 2012.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports the Company's application for a certificate of public convenience and necessity ("CPCN") for the construction of Energy Gateway South (Segment F) ("Gateway South"), which consists of the following facilities:

- A new 416-mile, high-voltage 500-kilovolt ("kV") transmission line from the Aeolus substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. Approximately 183 miles of Gateway South is located in Utah.

- Rebuilding certain 345-kV transmission facilities in and around the Mona and Clover substations.
- Construction of a four-mile, high voltage 230-kV transmission line from the Aeolus substation to the Freezeout Substation near Medicine Bow, Wyoming.
- Two new series compensation stations.
- Expansion of the Aeolus, Anticline, and Clover substations along with modifications to the Mona substation.
- Additional shunt capacitors at Bonanza (Utah), Riverton and Mustang (Wyoming) substations.
- Additions and modifications to various remedial action schemes, voltage controllers and control schemes necessary to ensure protection and control of the grid after integration of Gateway South.

My testimony also explains the relationship between Gateway South and Gateway West – Windstar-Aeolus (Segment D.1), a 59-mile, 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming and re-construction of an existing, 57-mile, 230-kV transmission line from the Shirley Basin substation to the Dave Johnston substation near Glenrock, Wyoming ("Gateway West Segment D.1"), (collectively, the "Transmission Projects"). Both Transmission Projects are necessary to interconnect the majority of the new low-cost wind resources in eastern Wyoming selected in the 2020 All Source Request for Proposals ("2020AS RFP"). Therefore, the customer benefits of Gateway South arising from the ability to interconnect additional wind resources must also account for the costs and benefits of Gateway West Segment D.1, as reflected in the economic analysis in the direct testimony of Company witness Mr. Rick T. Link. To the extent my testimony is addressing the interconnection of additional resources, it will generally refer to the Transmission Projects together.

I also provide an overview of the status of the permits that are required for construction of Gateway South.

Q. Please summarize your testimony.

A. Gateway South is an important component of the Company's Energy Gateway Transmission Expansion Project ("Energy Gateway") and has long been recognized as a key transmission segment in the region's long-term transmission planning. By constructing Gateway South before the end of 2024, the Company can provide substantial customer benefits. Gateway South supports the Company's short- and long-term energy demands and will strengthen the overall reliability of the existing transmission system. The Transmission Projects (i.e., Gateway South together with Gateway West Segment D.1) will enable interconnection of new generating facilities to meet projected resource needs. These resources can qualify for federal renewable tax credits, making them lower cost than other resource alternatives.

PacifiCorp used the OATT study process to identify the construction of the Gateway South as a prerequisite to reliably providing service in response to nearly 2,500 megawatts ("MW") of transmission and interconnection service requests, and Gateway South was listed in multiple FERC-jurisdictional executed contracts accordingly. Thus, to satisfy its obligations under its Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT"), the Company must develop the Transmission Projects and bring them into service by December 31, 2024.

Congestion on the current transmission system in eastern Wyoming limits the ability to deliver energy from eastern Wyoming to PacifiCorp load centers in Wyoming, Idaho, Utah, and the Pacific Northwest. Gateway South will help relieve this congestion and increase the transmission capacity from southeast Wyoming to central Utah by 1,700 MW. Gateway South, together with the Gateway West Segment D.1 project transmission system reinforcements, will allow the Company to interconnect up to approximately 2,030 MW of renewable resources and create substantial benefits for Utah customers and customers throughout the Company's service area. Gateway South will also enhance the Company's ability to comply with mandated North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability and performance standards.

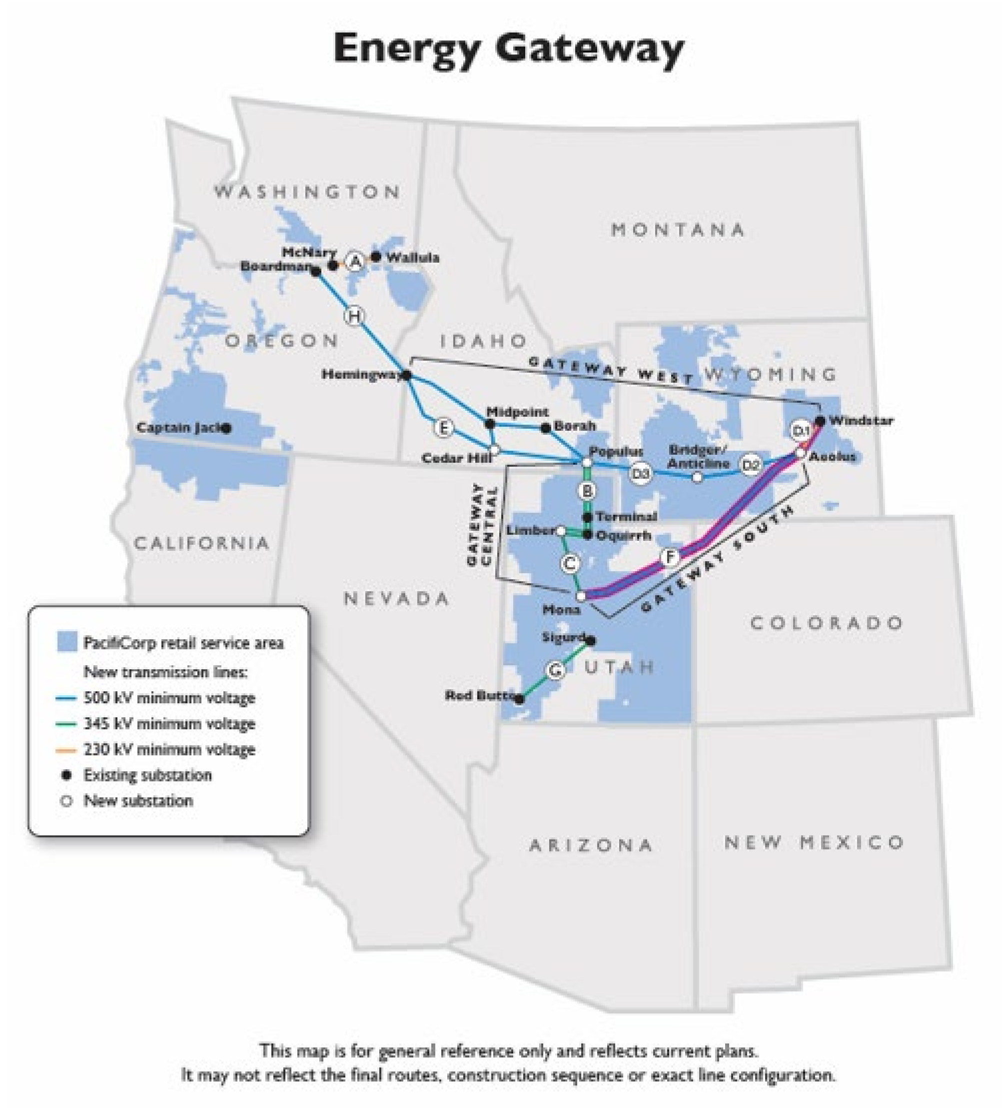
Construction of Gateway South will enable the Company to more efficiently use existing generation resources in Wyoming to serve its customers in Utah, Wyoming, Idaho, and the Pacific Northwest. Gateway South will also better position the Company to interconnect and integrate future resources in southeastern Wyoming and more efficiently serve expected customer load.

In addition to increasing the transmission capacity out of southeastern Wyoming and into central Utah, Gateway South will also provide critical voltage support to the Company's transmission network and enhance the overall reliability of the transmission system by adding incremental new transmission capacity between the Company's existing thermal and renewable facilities and future facilities and other sources of energy in Utah. Additional transmission paths will mitigate the impact of outages on the existing system.

Q. Please describe the location of the Transmission Projects within the Energy Gateway Project.

A. Figure 1 shows the general location of Gateway South and Gateway West Segment D.1 within the Energy Gateway Project:

Figure 1



DESCRIPTION OF GATEWAY SOUTH

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 16,900 miles of transmission lines ranging from 46 kV to 500 kV across multiple western states. PacifiCorp has nearly 1.9 million customers with approximately 960,000 customers located in Utah. Utah is located (along with Idaho and Wyoming) in PacifiCorp's eastern balancing authority area ("BAA"), PacifiCorp East ("PACE"), which has over 12,000 circuit-miles of transmission lines and a record peak demand of 9,142 MW. A new record peak was reached in PacifiCorp's overall system on August 17, 2020, at 12,709 MW. The PACE peak at that time was 9,131 MW even with COVID-19 still impacting customer demand.

Q. Is PacifiCorp's transmission system interconnected with any third-party systems?

A. Yes. PACE alone is interconnected with 17 other systems, including Arizona Public Service, Bonneville Power Administration ("BPA"), NV Energy, Los Angeles Department of Water & Power, NorthWestern Energy, WALC-Phoenix, Idaho Power, WACM-Loveland, Western Area Power Administration, Black Hills Power, Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative, Basin Electric Power Cooperative, Intermountain Power Agency, Tri-State Generation & Transmission Association, and Public Service Company of New Mexico.

Q. Please describe the Gateway South transmission project.

A. Gateway South is an extra-high voltage, single-circuit 500-kV alternating current transmission line that extends approximately 416 miles from southeastern Wyoming to northern Utah. Gateway South is also referred to as Segment F of Energy Gateway.

Q. Where does Gateway South begin and end?

A. Gateway South will begin at the Aeolus substation, which is located near Medicine Bow, Wyoming, and was recently constructed as part of the Aeolus-to-Bridger/Anticline segment D.2 of the Gateway West Transmission Line Project. From the Aeolus substation, the line extends west to Wamsutter, Wyoming, and then generally south to the Colorado border. From there, the line crosses through the northwest corner of Colorado, and enters Utah, eventually terminating at the Clover substation near Mona, Utah.

Q. Please describe Gateway South's proposed route.

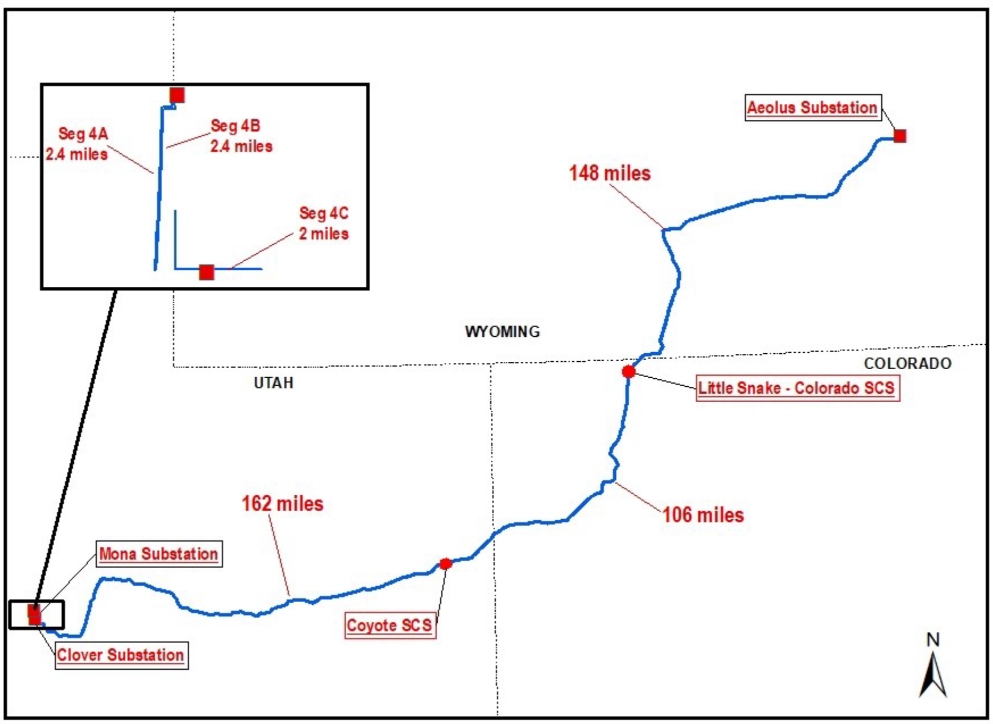
A. After leaving the Aeolus substation, for approximately 91 miles the line runs roughly parallel to the nearly completed Aeolus-Bridger/Anticline 500-kV transmission line, which runs southwest and then west. Approximately 12 miles west of the existing Latham substation, the line turns south towards the Colorado state line for the next 52 miles.

After crossing into Colorado, the line runs for five miles before entering the proposed Little Snake series compensation substation. After exiting the Little Snake substation, the transmission line runs south and then west for the next 85 miles before entering Utah, which occurs roughly five miles southwest of Dinosaur, Colorado.

The transmission line then extends another 21 miles southwest to the proposed Coyote series compensation substation. After the Coyote substation, the line runs west for 168 miles across Uintah and Duchesne Counties in Utah before entering Spanish Fork Canyon.

Once in Spanish Fork Canyon, the line generally follows U.S. Highway 6 from Solider Summit to near the intersection with U.S. Highway 89. At that point, the line turns south and generally follows U.S. Highway 89 and existing transmission line facilities before entering Sanpete County. The line then runs parallel to existing transmission facilities for three miles before turning west to enter Salt Creek Canyon and then routing east and north of Nephi, Utah into the Clover substation. Figure 2 is a high-level map of the proposed route:

Figure 2



Q. Does Gateway South increase the amount of generation that can be interconnected to and delivered across the Company's transmission system?

A. Yes. The Transmission Projects (Gateway South and Gateway West Segment D.1) will allow the Company to interconnect an additional 2,030 MW of generation resources in eastern Wyoming and increase the system transfer capability by approximately 875 MW from the Windstar/Dave Johnston area south to Shirley Basin/Aeolus. This will create approximately 1,700 MW of incremental transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover).

Q. Has the Company conducted any studies to verify these figures?

A. Yes. WECC path rating studies previously performed for the Aeolus South transmission path established the 1,700 MW path rating for the full Energy Gateway Project configuration, which can be achieved once Gateway South, Gateway West Segment D.1, and Gateway West Segment D.2 are in service. Additionally, the Company performed preliminary transfer capability assessment/System Operating Limit ("SOL") studies, which modeled the Gateway South and Gateway West Segment D.1, together with Gateway West Segment D.2. These studies confirmed the 1,700 MW path rating on Gateway South and the ability to interconnect up to 2,030 MW of wind generation in southeast Wyoming.

Q. Did the studies require the retirement of the Dave Johnston plant to achieve these increases?

A. No. The Company's studies have shown that the 1,700 MW transfer capability on the Gateway South transmission path can be achieved with or without Dave Johnston generation being on-line because of the location of the Dave Johnston plant. Dynamic voltage control was modeled at the Dave Johnston plant when generation was reduced to zero.

Q. Does construction of Gateway South include any related modifications to the Company's transmission system?

A. Yes. The Company must also modify the existing 345-kV transmission infrastructure in the Mona/Clover area. Specifically, the Company proposes to reconstruct and reconductor approximately five miles of the existing single-circuit Mona-to-Clover 345-kV #1 and #2 transmission lines. In addition, the existing 345-kV Huntington-to-Mona transmission line will be rerouted through the Clover substation via two miles of new 345-kV transmission line. The 345-kV series reactors at Mona will be relocated to Clover and serially connected to the Huntington – Clover 345-kV line.

The Company also proposes installing additional shunt capacitors at the Bonanza 138-kV substation in Utah and the Mustang 230-kV and Riverton 230-kV substations in Wyoming.

The Company must also modify the Aeolus remedial action scheme.

Q. What types of towers and conductors will be used to construct Gateway South?

A. Gateway South will be constructed using approximately 1,570 structures utilizing a mixture of self-supported lattice steel towers and guyed-v towers with heights ranging from about 140 to 200 feet. In select areas a tubular steel H-frame will be deployed with a height range of about 110 to 165 feet. The selection of tower for each location is based on a combination of access, terrain, environmental constraints, efficiency and engineering preference.

The self-supported steel lattice towers will have a "flat" configuration with each phase being parallel to each other in a horizontal arrangement. The guyed-v towers have a similar phase configuration, though are supported by one foundation and four guy anchor points.

The conductor for Gateway South will be triple bundled 1272 kcmil 45/7 Aluminum Conductor Steel Reinforced ("ACSR") "Bittern" per phase. Each conductor in the phase bundle will have a diameter of 1.345 inches, with three phases, comprised of three conductors each, for a total of nine conductors in the circuit.

In addition, each of the transmission line segments will also carry two overhead ground wires. One of the wires will be galvanized steel while the other will be optical ground wire ("OPGW") to facilitate communications. The wires will have a diameter of approximately 0.5 inches and 0.64 inches respectively. Optical signal regeneration sites are proposed in the segment between the Aeolus and Little Snake substations and also between the Coyote and Clover substations.

Q. What types of towers and conductors will be used to construct the 345-kV transmission lines in the Clover/Mona area?

A. The 345-kV work will use a combination of tower types based on circuit design and engineering characteristics. The 5-mile rebuild of the existing single circuit Mona-to-Clover 345-kV transmission line with H-frame construction with one circuit per structure with H-frame tubular steel or self-supported lattice for the dead-end and large angle structures. The conductor configuration will be triple bundle 1272 ACSR "Bittern." The 'loop in' work associated with the Huntington-to-Mona line into the Clover substation will use single circuit versions of the towers described above utilizing a double bundle configuration of 954 ACSR "Rail" conductor.

In addition, each of the transmission line segments will also carry two overhead ground wires. One of the wires will be galvanized steel while the other will be OPGW to facilitate communications. The wires will have a diameter of approximately 0.5 inches and 0.64 inches respectively.

Q. Will Gateway South require modifications to any substations?

A. Yes. Gateway South requires expansion of both the Aeolus substation, located near Medicine Bow, Wyoming, and the Anticline substation, located near Point of Rocks, Wyoming. Both the Aeolus and Anticline substations are new substations that are being constructed in accordance with the resource approval granted by the Commission in 2018 for the construction of the Aeolus-to-Bridger/Anticline transmission line. In addition, Gateway South requires expansion of the Clover substation.

Q. Please describe the proposed work at the Aeolus substation.

A. The existing Aeolus 500/230-kV substation constructed as part of Energy Vision 2020 will be expanded by approximately 14 acres to accommodate the Gateway South project. The substation will be constructed using conventional air insulated bus and equipment.

Construction of the Aeolus substation will require the following:

- Expansion of the existing 500-kV yard including all work to support the termination of one 500-kV transmission line to the Coyote series compensation substation, including completing two 500-kV breaker bays to support termination of the 500-kV line and connection to the high side of the 500/230-kV transformers;
- Installation of six single phase 500/230-kV transformer units with one additional spare unit;
- Installation of one 500-kV shunt capacitor, three single phase line reactors and one 138-kV neutral reactor;

- Completion of all site development, civil work, bus work, protection and controls, security, and communications;
- Within the existing 230-kV yard, additional circuit breakers will be added to support the 500/230-kV transformers and the new Aeolus – Freezeout #2 circuit. This will require two new additional bays to be constructed in the area previously prepared for expansion. Installation of two 230-kV shunt capacitors and one shunt reactor; and
- Implementation of modifications to the Aeolus remedial action scheme will be required to take into account tripping of Gateway South and the Clover 500/345-kV transformer.

A preliminary one-line diagram and general layout is included in Exhibit RMP__ (RAV-1) to my testimony.

Q. Please describe the proposed work at the Anticline substation.

A. The existing Anticline 500/345-kV substation constructed as part of Energy Vision 2020 will be expanded by approximately three acres to accommodate the Gateway South project. The substation will be constructed using conventional air insulated bus and equipment.

Construction of the Anticline substation will require the following:

- Expansion of the existing 345-kV yard including all work to support the installation of phase shifting transformers;
- Installation of three - three phase 345-kV 533.3-megavolt amperes (“MVA”) phase shifting transformer units;
- Installation of two 345-kV breakers; and

- Completion of all site development, civil work, bus work, protection and controls, security, and communications.

A preliminary one-line diagram and general layout is included in Exhibit RMP__ (RAV-1).

Q. Please describe the proposed expansion of the Clover substation.

A. The existing Clover substation near Mona, Utah must be expanded by approximately 60 acres. The expansion is sited on parcels of land owned by the Bureau of Land Management and PacifiCorp. The expanded substation will include additional security fencing and an improved access road, and will be constructed using conventional air insulated bus and equipment.

Construction of the Clover substation will require the following:

- Modification and expansion to the existing 345-kV substation with extension of the main bus, addition of two 345-kV shunt reactors;
- Relocation of the existing Limber/Oquirrh – Clover transmission line termination from the east side of the substation to a new line termination on the west side of the substation. This will be accomplished through the addition of a 345-kV breaker and half line termination bay. This will then allow connection of the new 345-kV shunt reactors;
- Construction of two further 345-kV breaker and half bays to allow connection to the low side of the second 500/345-kV transformer;
- Addition of a new line termination bay including three, 345-kV breakers to accommodate a breaker and a half bay configuration for the re-routing of the Huntington – Mona 345-kV transmission line via Clover;

- Installation of a 345-kV series reactor relocated from the Mona substation;
- Construction of the new 500-kV substation yard including all work to support the termination of one 500-kV transmission line from the Aeolus substation;
- Construction of two 500-kV breaker bays to support termination of the 500-kV line and connection to the high side of two banks of 500/345-kV transformers;
- Installation of six single phase 500/345-kV transformer units with one additional spare unit;
- Installation of two 500-kV shunt capacitors, three single phase 500-kV line reactors and one 138-kV neutral reactor; and
- Completion of all site development, civil work, bus work, protection and controls, security and communications, and construction of a 500-kV control building including site emergency power.

A preliminary one-line diagram and general layout is included in Exhibit RMP__(RAV-1).

Q. Please describe the series compensation stations.

A. Due to the length of Gateway South (416 miles), two series compensation stations will be inserted in the line to reduce net transmission line impedance and improve the power transfer capability of the line. The addition of series compensation also improves power flow control, voltage regulation and increases transient stability margin of line.

The first proposed series compensation substation (Little Snake Colorado) will be located in northern Colorado approximately 148 miles from the Aeolus substation and 30 miles north of Maybell, Colorado. The second proposed series compensation site (Coyote) will be located 106 miles from Little Snake and around five miles southwest of the DG&T Bonanza generating station in Utah.

Q. Please describe the proposed new Little Snake series compensation substation.

A. The proposed Little Snake series compensation substation will be located in northern Colorado, approximately 148 miles from the Aeolus substation and 30 miles north of Maybell, Colorado on a Bureau of Land Management-owned parcel. The new series compensation substation will occupy an area of approximately 20 acres and include security fencing and a small access road and will be constructed using conventional air insulated bus and equipment. The Little Snake series compensation substation will provide a method to connect the 500-kV transmission line to the series compensation equipment. The site will be designed to allow for future expansion.

Construction of the Little Snake series compensation substation will require the following:

- Construction of the new 500-kV series compensation substation yard including all work to support the termination of one 500-kV transmission line from the Aeolus substation and another to the Coyote series compensation substation;
- Construction of 500-kV substation dead-end structures and overhead strain bus to accommodate connection to the series compensation equipment, disconnects, reactors and transition of the transmission line through the site;
- Installation of one, 2-segment 500-kV 2300/3105 Ampere series capacitor with bypass circuit breakers;

- Installation of six single phase 500-kV line reactors and two 138-kV neutral reactors;
- Completion of all site development, civil work, bus work, protection and controls, security, primary metering, communications, and construction of a control building including site emergency power.

A preliminary one-line diagram and general layout is included in Exhibit RMP__(RAV-1). The preliminary drawings included in my exhibit show the name of this series compensation substation as "Godiva", which has since been changed to "Little Snake".

Q. Please describe the proposed new Coyote series compensation substation.

A. The proposed Coyote series compensation substation will be located 106 miles from Little Snake and around five miles southwest of the DG&T Bonanza generating station, in Uintah County, Utah, on a Bureau of Land Management-owned parcel. The new series compensation substation will occupy an area of approximately 20 acres, will include security fencing and an upgraded access road, and will be constructed using conventional air insulated bus and equipment. The Coyote series compensation substation will provide a method to connect the 500-kV transmission line to the series compensation equipment. The site will be designed to allow for future expansion.

Construction of the Coyote series compensation substation will require the following:

- Construction of the new 500-kV series compensation substation yard including all work to support the termination of one 500-kV transmission line from the Little Snake series compensation substation and another to the Clover substation;

- Construction of 500-kV substation dead-end structures and strain bus to accommodate connection to the series compensation equipment, disconnects, reactors and transition of the transmission line through the site;
- Installation of one, 2-segment 500-kV 2300/3105 Ampere series capacitor with bypass circuit breakers;
- Installation of six single phase 500-kV line reactors and two 138-kV neutral reactors; and
- Completion of all site development, civil work, bus work, protection and controls, security and communications, and construction of a control building including site emergency power.

A preliminary one-line diagram and general layout is included in Exhibit RMP__(RAV-1).

Q. Please describe any other related substation scopes or miscellaneous works required to support Gateway South.

A. The project will include modifications at the Mona substation (approximately five miles north of Clover substation) to relocate an existing 345-kV series reactor to Clover, modify one existing 345-kV bay and the bus to create the Clover – Camp Williams 345-kV line, by combining the existing Camp Williams to Mona #3 line and Mona to Clover 345-kV #3 line into one line which bypasses overhead Mona substation. Additionally, upgrade of two 345-kV breaker and half bays to 3000 Ampere capacity will be required by the replacement of six breakers and associated switches.

Modifications to relays, protection systems, controls and communications as necessary to support safe operation of the facilities will also be required.

The project will also include, subject to additional verification upon identification of generation interconnects, additional shunt capacitors at:

- Bonanza: two 138-kV shunt capacitors and associated breakers;
- Mustang: two 230-kV shunt capacitors and associated breakers; and
- Riverton: one 230-kV shunt capacitor and associated breaker.

A number of other substations are expected to require relay modification work and other ancillary facilities may be necessary as preliminary engineering designs become final.

ESTIMATED COST AND TIMING OF THE TRANSMISSION PROJECTS

Q. Please describe the estimated total cost of Gateway South.

A. The following table provides a breakdown of the estimated total costs for each main component of Gateway South.

Confidential Table 1 - Gateway South

Item	**Cost Estimate ($m)**
Transmission	[redacted]
Substation	
Engineering	
ROW Acquisition	
PM/Environmental/Support	
Indirects	
Total	$2,074.00

Q. What is the estimated cost including Gateway West Segment D.1?

A. The estimated costs of the Transmission Projects including Gateway West Segment D.1 is $2.4 billion.

Q. Does the Company have the financial ability to construct Gateway South?

A. Yes. Similar to previously built components of the Energy Gateway Project, the Company intends to finance Gateway South through its normal internal and external sources of capital, including net cash flow from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions, and other sources. The financial impact will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates.

Q. Will the cost of Gateway South be included in PacifiCorp's transmission rates?

A. Yes. Gateway South is considered an integrated network transmission asset under PacifiCorp's OATT. As described in more detail later in my testimony, Gateway South not only provides a number of benefits to the transmission grid, but its construction, together with Gateway West Segment D.1, allows PacifiCorp to provide nearly 2,500 MW of OATT service requests. As a result, FERC precedent for ratemaking requires PacifiCorp to roll the costs of these assets into PacifiCorp's federal transmission rate base.

Q. How will the costs of Gateway South flow into PacifiCorp's transmission rates and who will pay these rates?

A. All transmission rates charged to wholesale transmission customers must be approved by FERC. PacifiCorp's transmission rate structure is a FERC-approved formula that has been in place since 2012. A formula rate is a method of calculating a rate but is not the rate itself; the actual transmission rate that is charged to wholesale transmission customers is produced annually by updating FERC-approved inputs to the formula rate.

Formula rates rely on annual updates using inputs from the detailed, publicly available, and audited FERC Form No. 1, along with other Company data. The annual update process includes transmission capital additions such as Gateway South.

Consistent with all other transmission assets, Utah retail rates would reflect the state's system allocation of the cost of Gateway South and a revenue credit for the third-party transmission customers that pay PacifiCorp's OATT rate, which offset, in part, the cost of PacifiCorp's transmission revenue requirement in retail rates.

Q. When does the Company expect to complete the construction of Gateway South?

A. The Company plans to have Gateway South in service by the end of 2024. As Mr. Link testifies, this plan is designed to cost-effectively address PacifiCorp's need for additional generation resources. As I will describe in more detail later in my testimony, one of the benefits of Gateway South is that it will support the addition of new generation resources. In order to take advantage of the full value of investment tax credits associated with new solar generation resources—which directly benefit Utah customers— Gateway South must be in service no later than December 31, 2024.

Q. Why did the Company move the completion of Gateway South to 2024, when the 2019 IRP indicated that it was expected to be placed in service in 2023?

A. The in-service date for Gateway South was intended to align with the expected in-service date for the new generation resources that would require Gateway South to interconnect to PacifiCorp's system. As Mr. Link testified, this alignment was designed to cost-effectively address PacifiCorp's need for additional generation resources. When the bids were received and evaluated in the 2020AS RFP, it became apparent that most bidders proposed a 2024 in-service date. Because the bids reliant on Gateway

South to interconnect were not proposing to interconnect in 2023, the Company was able to defer construction of Gateway South (and Gateway West Segment D.1) to 2024 without compromising the benefits supplied by new generation resources.

Q. Does the 2024 in-service date compromise the value of tax credits attributable to the generation resources selected in the 2020AS RFP?

A. No. As Mr. Link testifies, the deadline for production tax credits for new wind resources has been extended to 2024, which means that customers will still receive the full benefits of the credits when the Transmission Projects and the new generation resources achieve commercial operation in 2024.

Q. Does the 2024 in-service date affect the Company's ability to meet its obligations under its OATT to provide interconnection and transmission service?

A. No. The current schedule still allows the Company to meet its obligations under its OATT to reliably accommodate approximately 2,500 MW of interconnection and transmission service requests governed by 13 executed contracts that require the construction of one or both of the Transmission Projects, which is discussed in more detail below. To provide the contractually required transmission service and interconnection service by 2024, the Company expects the Transmission Projects to go into service before the end of 2024.

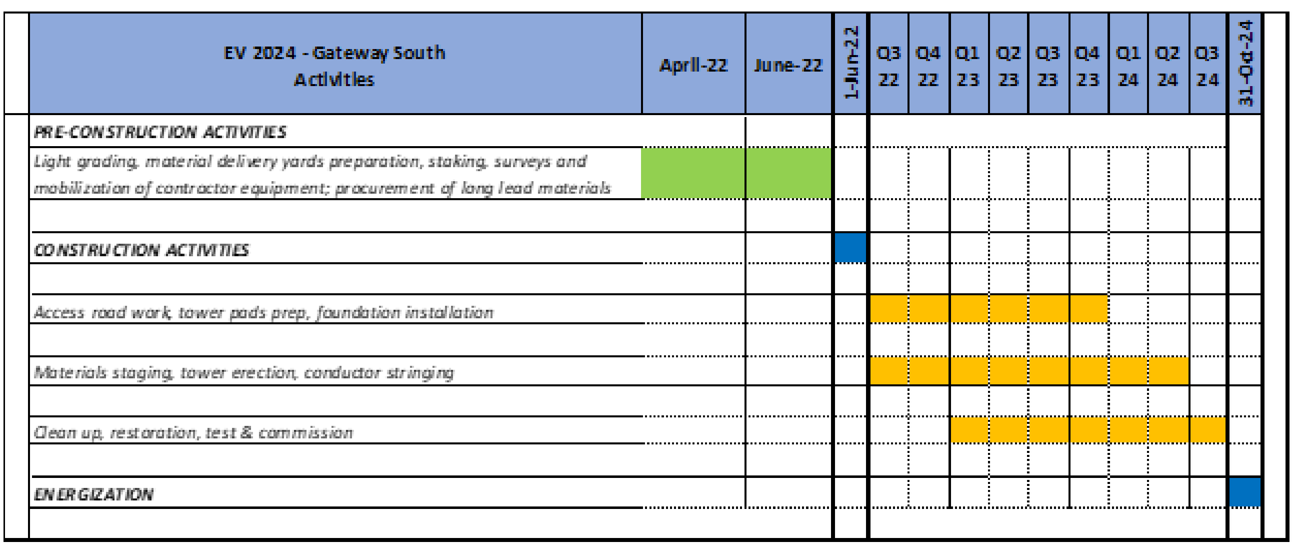
Q. Given the new 2024 in-service date, when must the Company start construction of Gateway South?

A. To achieve an in-service date before the end of 2024, the Company must start construction no later than June 2, 2022, which will allow three full construction seasons. To meet this timeline, the Company must receive a CPCN from the Commission by June 1, 2022.

Q. Will any project related activities commence prior to June 2, 2022?

A. Yes. The Company plans to begin pre-construction activities before June 2, 2022. These pre-construction activities include moving heavy equipment to the project area, ground survey work for transmission tower pads and access roads, and pre-construction cultural and biological surveys, as required by the Bureau of Land Management. Additionally, the contractor will obtain its storm water pollution prevention plan permit, will identify sources of water for construction use to meet regulatory stipulations, and will make the necessary pre-construction preparations required by those permits. By undertaking these pre-construction activities prior to June 2, 2022, the Company will be well positioned to begin actual construction once it has a CPCN. See Figure 3 below:

Figure 3



NECESSITY OF THE TRANSMISSION PROJECTS

Q. Does Gateway South facilitate PacifiCorp's compliance with federal reliability-related requirements?

A. Yes. PacifiCorp's obligation to operate its transmission system reliably primarily stems from two main requirements: (1) PacifiCorp's obligation to comply with its federal OATT that governs the rates, terms, and conditions of PacifiCorp's reliable provision of transmission and interconnection services; and (2) PacifiCorp's obligation to comply with federal mandatory reliability standards. As I will discuss in more detail in this section, PacifiCorp used the federal OATT study process to identify the construction of the Transmission Projects as a prerequisite to reliably meeting nearly 2,500 MW of transmission and interconnection service requests, and the Transmission Projects were listed in multiple FERC-jurisdictional executed contracts accordingly. In addition, the Transmission Projects facilitate PacifiCorp's compliance with federal reliability standards.

Compliance with OATT and Executed Contracts

Q. Can you provide some background on the creation of PacifiCorp's OATT?

A. Yes. I am not a lawyer, but I am aware that in 1996, FERC issued a landmark order establishing its open access transmission policies.[1] In short, FERC required that transmission providers offer third parties "open access" to their transmission systems. To implement this requirement, FERC created a pro forma OATT with standardized rates, terms, conditions, processes, and contracts to govern the provision of

[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996).

transmission services. All transmission providers must model their OATT after FERC's pro forma OATT and maintain their FERC-approved OATT on file with FERC at all times. Any deviations from the pro forma OATT must be filed with FERC for approval.

Q. What services does the federal OATT govern?

A. The OATT primarily governs two basic services: (1) transmission service; and (2) generator interconnection service.

Q. How is OATT service requested?

A. OATT service is requested through a FERC-mandated public website called the Open Access Same-Time Information System ("OASIS").

Q. What happens after PacifiCorp receives a request for OATT service?

A. PacifiCorp must follow the OATT process to perform a series of increasingly more involved engineering studies that evaluate the cost and timing requirements associated with providing the requested service. PacifiCorp must issue reports summarizing the results of its OATT studies and make those reports publicly available by posting them on OASIS. At the end of the study process, PacifiCorp must tender the requesting party a standardized OATT contract that memorializes the cost and timing requirements identified in the study process.

Q. What do you mean by "cost and timing requirements" associated with providing the requested OATT service?

A. When PacifiCorp receives a request for OATT service, it must evaluate whether it can reliably provide that service on its existing transmission system within the timeframe requested. For example, if the existing transmission system is capable of reliably delivering the requested amount of additional transfer capacity associated with a transmission service request or reliably interconnecting the requested amount of generation associated with a generator interconnection request, the OATT studies evaluating that request are likely to state that the service can be granted within the requested timeframe with minimal or no transmission system upgrade costs.

If, on the other hand, the existing transmission system is *not* capable of reliably delivering or reliably interconnecting additional capacity in the area of the system where the OATT service has been requested, PacifiCorp cannot simply conclude no service can be provided and reject the service request. Rather, the OATT requires PacifiCorp to identify what transmission system upgrades are needed to accommodate the request, as well as the estimated cost and timing associated with constructing those upgrades. Those upgrades then become requirements identified in the OATT customer's OATT contract.

OATT Obligation to Construct Transmission System Upgrades

Q. Does the OATT require PacifiCorp to construct transmission system upgrades necessary to grant OATT service requests?

A. Yes. The OATT requires PacifiCorp to construct transmission system upgrades necessary to grant OATT requests for transmission service and OATT requests for generator interconnection service. This obligation to construct is found in the OATT's provisions governing: (1) network transmission service; (2) point-to-point transmission service; and (3) generator interconnection service.

Q. Can you describe the OATT's requirement to construct transmission system upgrades in response to a network transmission service request?

A. Yes. The OATT's network transmission service provisions require a transmission provider to "plan, **construct**, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System" and "endeavor to **construct** and place into service sufficient transfer capability" to deliver network customer resources to load.[2]

Q. Can you describe the OATT's requirement to construct transmission system upgrades in response to a point-to-point transmission service request?

A. Yes. The OATT's point-to-point transmission service provisions require a transmission provider to "use due diligence to **expand or modify** its Transmission System to provide the requested Firm Transmission Service" if the transmission provider cannot accommodate the request because of insufficient capability on its system.[3] PacifiCorp's OATT provides as follows:

> In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be **obligated to expand or upgrade** its Transmission System pursuant to the terms of Section 15.4.[4]

[2] PacifiCorp OATT, Section 28.2 (emphasis added).
[3] PacifiCorp OATT, Section 15.4 (emphasis added).
[4] PacifiCorp OATT, Section 13.5 (emphasis added).

Q. Can you describe the OATT's requirement to construct transmission system upgrades in response to a generator interconnection service request?

A. Yes. Sections 36-52 of PacifiCorp's OATT contain comprehensive rules for interconnecting new generators, including the identification and construction of new network upgrades if they are necessary to grant the request. Importantly, the OATT process does not give PacifiCorp any tariff authority to refuse an interconnection request simply because it would require new network upgrades.

Q. Has FERC clarified this OATT requirement?

A. Yes. While I am not a lawyer, I am aware that in 2003, FERC issued another series of landmark "open access" orders specifically focused on the standardization of the rates, terms, conditions, processes, and contracts under which a transmission provider offers generator interconnection service.[5] FERC established pro forma interconnection provisions to be included in every transmission provider's OATT on file with FERC and directed that transmission providers file any proposed deviations from the pro forma interconnection provisions with FERC for approval.

In that interconnection proceeding, FERC explained that its pro forma interconnection services "provide for the **construction of Network Upgrades** that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."[6]

[5] In 2003, FERC standardized its rules for large generators in the Order No. 2003 proceeding in FERC Docket No. RM02-1. In 2005, FERC standardized its rules for small generators in the Order No. 2006 proceeding in FERC Docket No. RM02-12.
[6] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 767 (2003) (emphasis added).

Q. Does the OATT obligation to construct in response to service requests apply even if the upgrades at issue are previously planned transmission projects?

A. Yes. The OATT obligation to construct applies to both (1) transmission system upgrades triggered for the first time in response to an OATT request and (2) previously planned transmission projects identified as necessary to grant an OATT request. By way of background, FERC required transmission providers to amend their OATTs to address transmission planning obligations and processes. For PacifiCorp, Attachment K of its OATT sets forth inter-regional, regional, and local transmission planning processes that are overseen by FERC, the North American Electric Reliability Corporation ("NERC"), and the Western Electricity Coordinating Council ("WECC"). As with all provisions in the OATT, PacifiCorp secured FERC approval of the Attachment K provisions and must file any proposed changes with FERC.

Q. How does this FERC-approved OATT Attachment K process relate to the OATT's obligation to construct transmission system upgrades?

A. PacifiCorp's FERC-approved Attachment K makes clear that once a planned transmission project is required to be in service in order for PacifiCorp to grant an OATT request for point-to-point transmission service or generator interconnection service, PacifiCorp is obligated to construct the planned facilities: "Transmission Provider shall use Point-to-Point Transmission Service usage forecasts and Demand Resources forecasts to determine system usage trends, and such forecasts do not obligate the Transmission Provider to construct facilities **until** formal requests for either Point-to-Point Transmission Service or Generator Interconnection Service requests are received pursuant to Parts II and IV of the Tariff."[7]

Q. If PacifiCorp's ability to provide requested OATT service is contingent upon a component of PacifiCorp's long-term transmission plan being in service, do the OATT studies and OATT contracts make that clear?

A. Yes. If PacifiCorp cannot reliably provide requested OATT service until a component of PacifiCorp's long-term transmission plan is in place, that upgrade would be listed in the OATT study and OATT agreement as a "Contingent Facility." FERC recently formalized this definition with respect to generator interconnection service, and approved the following definition for inclusion in PacifiCorp's OATT:

> Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.[8]

The Transmission Projects are Requirements in FERC-Jurisdictional Executed Contracts

Q. How do these OATT obligations to construct transmission system upgrades relate to the Transmission Projects?

A. The Transmission Projects have become a lynchpin in PacifiCorp's ability to provide thousands of MW of requests for FERC-jurisdictional OATT generator interconnection service and transmission service. Stated more directly, under my signature as Vice President of PacifiCorp Transmission, PacifiCorp has executed 13 transmission service

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[7] PacifiCorp OATT, Attachment K (emphasis added).
[8] PacifiCorp OATT at section 36.

and generator interconnection service contracts that list either one or both of the Transmission Projects Contingent Facilities. This means that PacifiCorp *cannot provide* the contracted services to 13 contractual counterparties without constructing the Transmission Projects.

Transmission Service Contract Obligations

Q. Can you describe the transmission service contract obligations dependent on the Transmission Projects?

A. Yes. PacifiCorp received an OATT request to provide 500 MW of point-to-point transmission service from Aeolus to Mona. In accordance with the OATT process I outlined above, PacifiCorp determined it could not deliver an additional 500 MW of power on its existing transmission system, so it performed an OATT system impact study to determine what transmission system upgrades would be required to do so. PacifiCorp's OATT system impact study report, which is publicly posted to OASIS,[9] states that PacifiCorp's planned Gateway South 500 kV line from the Aeolus substation to the Clover substation near Mona, Utah must be in place to grant the requested FERC-jurisdictional point-to-point transmission service.

Q. Why did PacifiCorp conclude that the requested transmission service could not be provided on the existing transmission system?

A. The short answer is due to reliability concerns. As I walked through in more detail above, the OATT states that:

> where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-

[9] *See* Request No. Q2594 in PacifiCorp's transmission service queue, available at: http://www.oasis.oati.com/ppw/index.html.

> Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4.

That was the case here because the current transmission system could not reliably support the transfer of an additional 500 MW of power from Aeolus to Mona. Under steady-state conditions, increasing transfers between eastern Wyoming (Aeolus) and central Utah (Mona) by 500 MW would result in a voltage collapse of the PacifiCorp east side transmission system for a minor system contingency in Wyoming or northern Utah. Such a voltage collapse would violate NERC and WECC reliability standards, which I will address in more detail later in my testimony, would degrade the reliability of service to other customers, and would negatively impact other utilities in the Western Interconnection.

Q. Why did PacifiCorp identify Gateway South as the "contingent facility" solution to the reliability concern?

A. As I noted above, the OATT service request is for 500 MW of point-to-point service starting on January 1, 2024 from Aeolus to Mona—the exact path of the proposed Gateway South line. Gateway South is estimated to provide an additional 1,700 MW of transfer capability by the end of 2024. Therefore, Gateway South was identified as the contingent facility that would allow PacifiCorp to provide the requested MW amount, along the requested path, and in the same general requested timeframe.

Q. Could you provide the requested FERC-jurisdictional transmission service with a much smaller upgrade if you had not relied upon PacifiCorp's long-term plan for the upgrade solution?

A. No. As a threshold matter, I will note that identifying a long-term transmission plan component as a contingent facility to providing requested service is consistent with the OATT's directive that transmission providers make efficient use of the estimated capabilities and estimated timelines associated with the transmission provider's long-term transmission plan. This may not always lead to the identification of a transmission system upgrade that creates the precise amount of transfer or interconnection capability needed to grant the requested service. That is the case here where Gateway South creates more transfer capability than is needed to grant the point-to-point request. However, I agree with FERC that it is generally far more efficient to identify planned projects when possible because those projects have gone through extensive local, regional and inter-regional planning coordination spanning multiple years. Additionally, significant permitting efforts and other regulatory processes can take years to get final approvals. Therefore, projects that are already well advanced in this process are more likely to be successful.

Q. Did identifying Gateway South as a contingent facility for this specific point-to-point transmission service request result in those efficiencies?

A. Yes. In fact, the planned Gateway South project is not significantly greater than the transmission system upgrades that would be needed to grant just this isolated request based on an evaluation PacifiCorp performed in response to stakeholders in the Company's 2019 Integrated Resource Plan proceeding before the Commission.

Specifically, stakeholders asked PacifiCorp to provide information about how its preferred portfolio and system costs might be impacted if Gateway South is assumed to be removed from the preferred portfolio. In response, PacifiCorp explained that, even if Gateway South is not constructed, it is unrealistic to assume that PacifiCorp transmission would not be obligated to construct *any* transmission system upgrades out of eastern Wyoming to accommodate FERC-jurisdictional requests for OATT interconnection service and transmission service. PacifiCorp continued that, even conservatively ignoring the transmission system upgrades that would be required to grant all of the requests it has received for FERC-jurisdictional interconnection and transmission service and focusing only on the 500 MW point-to-point transmission service request I described above, PacifiCorp estimated it would need to construct, at a minimum, a 230-kV transmission line by the end of 2023, at a cost of approximately $1.4 billion.

Q. So does the OATT obligation to construct apply only to a 230-kV transmission line, rather than a 500-kV transmission line, from Aeolus to Mona?

A. No. PacifiCorp estimated that a 230-kV line would be required to grant the 500 MW transmission service request, and *only* that request. As I will discuss in more detail in the next section, PacifiCorp has far more than a single request for OATT service in Wyoming, and PacifiCorp could not grant all of the requests with only a 230-kV line.

Q. Did you execute a FERC-jurisdictional transmission service contract with the entity requesting the 500 MW of point-to-point transmission service?

A. Yes. PacifiCorp followed the OATT transmission service study process, which ends with the transmission provider tendering to the transmission customer an OATT pro forma draft transmission service agreement along with the system impact study report I described above. The transmission customer executed the transmission service agreement.

Interconnection Service Contract Obligations

Q. Can you describe the interconnection service contract obligations dependent on the Transmission Projects?

A. Yes. PacifiCorp has received approximately 15,000 MW of requests for generator interconnection service in eastern Wyoming. In accordance with the OATT process I described above, PacifiCorp has determined it cannot reliably accommodate any additional generator interconnections in that area without improvements in place. As a result, PacifiCorp has performed and posted to OASIS many system impact studies identifying either one or both of the components of the Transmission Projects (Gateway South and Gateway West Segment D.1) as contingent facilities necessary to grant requested interconnection service. Table 2 below identifies these results at a high level:[10]

[10] The studies provide additional detail on these requirements and are available by cross-referencing the queue numbers in this table with PacifiCorp's interconnection queue, available at: http://www.oasis.oati.com/ppw/index.html.

Table 2

Q#	MW	One or Both Transmission Projects Required
Q409	320	Gateway South
Q713	350	Gateway South, Gateway West Segment D.1
Q719	280	Gateway South, Gateway West Segment D.1
Q783	30	Gateway South, Gateway West Segment D.1
Q784	80	Gateway South, Gateway West Segment D.1
Q785	100	Gateway South, Gateway West Segment D.1
Q789	74.9	Gateway South, Gateway West Segment D.1
Q801	80	Gateway South, Gateway West Segment D.1
Q802	50	Gateway South, Gateway West Segment D.1
Q807	75.9	Gateway South, Gateway West Segment D.1
Q835	190	Gateway South, Gateway West Segment D.1
Q836	400	Gateway South, Gateway West Segment D.1

Q. Why did PacifiCorp conclude that the requested generator interconnections could not be provided on the existing transmission system?

A. Again, the short answer is due to reliability concerns. As I walked through in more detail above, FERC requires transmission providers to identify the transmission system upgrades that need to be constructed to allow the interconnection customer to "flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner." Here, interconnecting additional generation in the eastern Wyoming area without construction of the Transmission Projects would result in a voltage collapse of the PacifiCorp east side transmission system for a minor system contingency in Wyoming or northern Utah. Such a voltage collapse would violate NERC and WECC reliability standards, as I discuss in more detail later in my testimony, would degrade the reliability of service to other customers and would negatively impact other utilities in the Western Interconnection.

Q. Would you have been able to reliably grant the requested generator interconnections with a much smaller upgrade if you had not relied upon PacifiCorp's long-term plan for the upgrade solution?

A. No. In fact, PacifiCorp transmission performed an analysis to test this question. First, we assumed there was no plan to construct the Transmission Projects. Next, we evaluated what, if any, transmission upgrades would be required to grant the first generator interconnection request that required the Transmission Projects. We continued to add projects and evaluate individual incremental interconnection requirements one at a time until we had added all of the requests currently dependent on the Transmission Projects.

The analysis showed that while no single project individually triggered the need for a 500-kV line, because of the cumulative nature of the project-specific studies, the Company would have been required to construct more and more 230-kV and 345-kV transmission lines. In total, the Company could interconnect an estimated 1,441 MW of additional generation resources, which represent 10 interconnection requests, before the next request triggered the need for a 500-kV line to interconnect. To interconnect those 10 projects, however, would cost approximately $1.53 billion dollars, the Company would have achieved only 814 MW of incremental transfer capability, and it would still have remaining interconnection requests in need of upgrade identification. By comparison, the Transmission Projects are estimated to cost $2.4 billion and provide approximately 1,700 MW of transfer capability and 2,030 MW of interconnection capability.

Q. What conclusions can you draw from the analysis you performed?

A. My primary conclusion is that PacifiCorp's identification of the planned Transmission Projects as the upgrade solution to reliably interconnect additional generation in eastern Wyoming did not lead to more significant upgrades than would have been otherwise required. The analysis demonstrates that the Company likely would have ended up in largely the same spot (i.e., identifying a 500-kV line) with fewer financial, interconnection, transmission, and operational efficiencies. As a result, it was not only consistent with the OATT to identify components of PacifiCorp's long-term transmission plan as contingent facilities in the interconnection studies, but it was also beneficial.

It is also important to remember that this analysis looked at interconnection requests in isolation, without regard to transmission service requests like the 500 MW point-to-point request I discussed at length previously. In reality, the OATT requires PacifiCorp to identify the transmission system upgrades necessary to grant *all* of the requests it receives, not just some. Based on the analysis I have discussed in my testimony, it would be impossible to do that without constructing Transmission Projects or their functional equivalent.

Q. Have you executed interconnection agreements identifying the Gateway South as a contingent facility?

A. Yes. I have executed 12 interconnection agreements that identify the Transmission Projects, i.e., Gateway South or Gateway South *and* Gateway West Segment D.1, as contingent facilities. The counterparties to these executed agreements have, in total, secured contractual rights to all of the estimated 2,030 MW of interconnection capability of the Transmission Projects.

Q. Does FERC's recent approval of PacifiCorp's interconnection queue reform proposal change PacifiCorp's obligation to comply with its executed interconnection contracts?

A. No, it reaffirms it. By way of background, in June 2019, PacifiCorp initiated a six-month stakeholder process to examine potential interconnection processing reforms to address the significant congestion in its interconnection queue, which at the time had 234 requests for over 40,000 MW of interconnection capacity.[11] PacifiCorp hosted a series of in-person stakeholder meetings and phone calls, including at PacifiCorp's corporate headquarters in Salt Lake City, Utah on October 9, 2019.

One of the primary issues discussed throughout the stakeholder process was how to transition from serial-queue processing that cumulatively studies each individual interconnection request and does not test the "commercial readiness" of any generator (i.e., FERC's long-standing, first-come, first-served process) to a first-***ready***, first-served process that studies requests in groups (called "clusters") on an annual basis and requires large, FERC-jurisdictional generators to demonstrate readiness as a prerequisite to receiving an interconnection study. Readiness may be proven by, for example, providing evidence that the generator has an executed term sheet, executed power-purchase agreement, or has been selected in a competitive solicitation process. One of the most critical elements to this transition discussion was whether any

[11] PacifiCorp posted all materials related to this stakeholder process, including issue lists, stakeholder written comments, straw proposals, and meeting dates, times, and attendees on OASIS: http://www.oasis.oati.com/ppw/index.html.

generators should be allowed to keep their serially processed studies or agreements without demonstrating readiness.

Initially, stakeholders strongly supported applying the new readiness testing requirements to all interconnection customers, even those that were already at the end of the study process or that had executed an interconnection agreement. The stakeholders reasoned that allowing parties with executed interconnection contracts to maintain their contractual rights without demonstrating any type of commercial readiness would prevent PacifiCorp from effectively clearing out its congested queue. In response, PacifiCorp initially included this broad application of the transition requirements in its straw proposals issued in September 2019 and November 2019 and planned to make it part of its ultimate proposal filed with FERC. After additional stakeholder discussions, however, it became clear there would be significant opposition to this approach, particularly from counterparties having executed contracts. FERC staff similarly signaled resistance to a proposal that would abrogate executed interconnection agreements.

As a result of this feedback, PacifiCorp's January 31, 2020, filing with FERC[12] reflected a modified transition proposal that: (1) allows generators to retain executed interconnection agreement rights without demonstrating commercial readiness; and (2) allows "late stage" generators, defined as any interconnection customer that reached the facilities study agreement stage or later by April 1, 2020, the option to keep their serially processed studies and proceed to an agreement reflecting those study results as long as, for large generators, they can demonstrate commercial readiness. In addition,

[12] PacifiCorp filed its queue reform proposal on January 31, 2020, in FERC Docket No. ER20-924.

given that the vast majority of the projects in PacifiCorp's interconnection queue are large, FERC-jurisdictional generators, PacifiCorp proposed ***not*** to require small, FERC-jurisdictional generators or state-jurisdictional qualifying facility generators of any size to provide evidence of commercial readiness at this time. PacifiCorp proposed these requirements to be reflected in PacifiCorp's very first cluster study, the "transition cluster," that will begin no later than October 31, 2020, and take approximately six months to complete. PacifiCorp also proposed limitations for requests that were too *early* in the process by limiting eligibility for the initial October 2020 transition cluster to only those interconnection customers that had a queue position by January 31, 2020.

In its May 12, 2020, order, FERC approved this transition approach, noting in particular with respect to the executed contracts that "PacifiCorp's Transition Process appropriately protects interconnection customers that are in the late stages of interconnection ***by not disrupting already signed interconnection agreements*** and continuing to process late-stage interconnection requests under the currently serial process, provided they meet the commercial readiness criteria."[13]

As I noted above, FERC's queue reform order does not change PacifiCorp's obligation to provide interconnection service under executed contracts, but rather emphasizes the importance of adhering to their terms.

Q. What would it mean for FERC-jurisdictional service requests with executed contracts if Gateway South is not constructed?

A. I cannot speak to the legal implications of the failure to construct the Gateway South for lack of a CPCN, or any resulting tension between state certificate law and federal

[13] PacifiCorp, 171 FERC ¶ 61,112 at P 144 (2020) (emphasis added).

requirements to expand the transmission system. I can, however, say that PacifiCorp, in good faith, acted consistently with the federal OATT process and obligations when it identified Gateway South as a transmission system upgrade that must be constructed to reliably provide the requested service. PacifiCorp also acted consistently with the federal OATT process when it listed Gateway South (and Gateway West Segment D.1) as a contingent facility in the executed contracts—contracts that are on file with FERC. If PacifiCorp is put in a position where it cannot construct Gateway South for lack of a CPCN, and it cannot provide the requested OATT service reliably on the existing system, the OATT would still require PacifiCorp to pursue transmission system upgrades out of eastern Wyoming that are necessary to accommodate FERC-jurisdictional requests for OATT service.

Compliance with Reliability Standards

Q. You mentioned above that there are two main drivers behind PacifiCorp's obligation to operate its transmission system reliably. Can you describe the second driver?

A. Yes. In addition to the reliability components of the OATT related to accommodating new service requests which I just discussed, FERC expanded the reliability-related elements of the federal regulatory structure in implementing the reliability directives contained in the Energy Policy Act of 2005. FERC did this by instituting mandatory reliability standards that all users of the bulk electric system ("BES") must follow, including transmission providers.

Q. Who oversees development of and compliance with transmission provider reliability standards?

A. FERC delegated authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards.

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.

Q. Is there a set of reliability standards most relevant to Gateway South?

A. Yes. A subset of the transmission reliability standards called the transmission planning standards ("TPL Standards") are most relevant to both the Transmission Projects. 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."[14] The TPL Standards, along with regional planning criteria (*i.e.*, regional planning criteria established by WECC and utility-specific planning

[14] *See* NERC Standard TPL-001-4, Transmission System Planning Performance Requirements, available at http://www.nerc.com/files/tpl-001-4.pdf.

criteria), define the minimum transmission system requirements to safely and reliably serve customers.

Q. How do NERC's and WECC's standards and criteria influence the need for the Transmission Projects?

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

The Company performs annual reliability assessments to determine whether 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 Company must also plan how it will respond to the second outage (this type of scenario is referred to as an N-1-1 condition).

The Transmission Projects, as part of Energy Gateway, have 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 for eight years. Gateway South's new transmission segment is particularly effective in increasing system reliability under the various multiple contingency categories of the TPL-001-4 standard.

Q. Absent construction of Gateway South, would the Company still need to demonstrate reliable operations under the various contingency categories of the TPL-001-4 standard and continue to construct transmission facilities in eastern Wyoming?

A. Yes. The only way PacifiCorp could stop pursuing construction of any transmission facilities in eastern Wyoming and maintain compliance with the TPL-001-4 standard is if the transmission system experienced ***no*** changes in loads or resources. As I discussed above, however, PacifiCorp has received, processed, and executed contracts associated with thousands of megawatts of requests for OATT service in eastern Wyoming—service that cannot be reliably provided absent construction of the Gateway South (and Gateway West Segment D.1) or their functional equivalent. Stated another way, the system impact studies for those OATT service requests identified that addition of *any* of the incremental generation projects requesting service would result in system deficiencies during N-1 or N-1-1 conditions in violation of TPL-001-4 if allowed to interconnect absent the Transmission Projects.

Separate from the incremental generation dependent on the Transmission Projects, the 2019 TPL-001-4 planning assessment identified three deficiencies on the existing system that are mitigated by the Transmission Projects and four additional deficiencies that are projected to happen by 2029 due to typical system changes and normal load growth. Further TPL-001-4 issues could arise with other types of system changes as well, such as a significant loss or addition of load. For these reasons, I do not believe it is reasonable to assume the Company could realistically stop pursuing construction of any transmission facilities in eastern Wyoming and maintain compliance with reliability standards.

BENEFITS OF GATEWAY SOUTH

Q. Please describe the benefits associated with construction of the Gateway South.

A. PacifiCorp's bulk transmission network is designed to reliably transport electric energy from a broad array of generation resources to load centers. There are many benefits associated with a robust transmission network, including:

- Reliable delivery of a diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
- Ability to meet aggregate electrical demand and customers' energy requirements at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
- Economic dispatch of resources within PacifiCorp's diverse system.
- Economic transfer of electric power to and from other systems as facilitated by the Company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
- Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
- Protection against market disruptions where limited transmission can otherwise constrain energy supply.

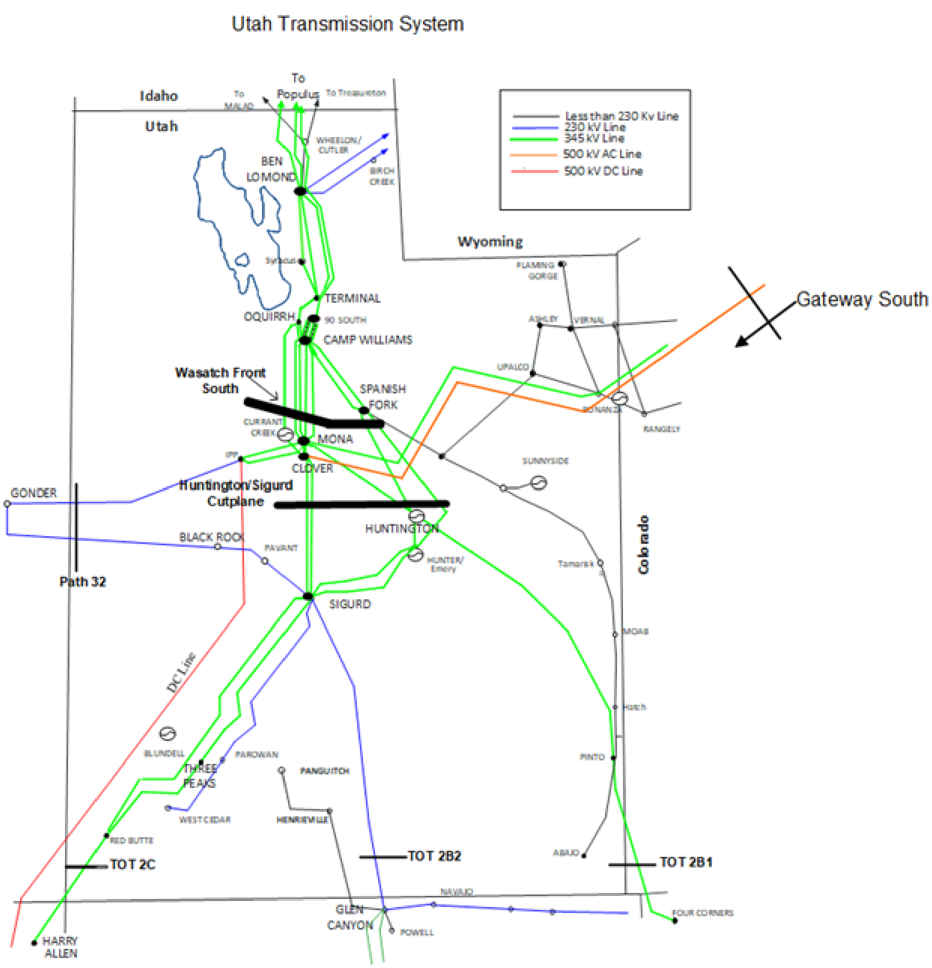
Q. Please describe in more detail how Gateway South will improve overall system reliability.

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 southern and northern Utah is comprised of several individual transmission lines or line segments. Figure 4 is a diagram of the existing Utah transmission system. A single outage on any of the individual lines or line segments due to storm, fire, or other interference can and does cause significant reductions in transmission capacity and can negatively impact the Company's ability to serve customers. The addition of the Gateway South provides another path into Utah to reliably serve customers during such line outages, such as outages of the transmission lines that form the Huntington / Sigurd cutplane, as shown in Figure 4. The line outages on this cutplane significantly reduces PacifiCorp's capability to bring resources from southern Utah. Line outages require the Company to significantly curtail generation resources to stabilize system voltages and require less efficient re-dispatch of system resources to meet network load requirements.

In the event of a line outage, the redundancy provided by Gateway South will allow the Company to continue to meet native load service obligations and continue to meet other contractual obligations to third parties. Strengthening this transmission and increasing system redundancy with Gateway South will benefit all customers by reducing the risk of outages and inefficient dispatch resulting from those outages. The addition of the Gateway South line at Clover, adds stability to that region for line outages in the area.

In addition, Gateway South 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 used. By relieving congestion and providing additional transmission paths, Gateway South will allow greater flexibility for the Company.

Figure 4



Q. Please describe the reliability benefits specific to Gateway South.

A. Construction of Gateway South will provide a parallel transmission path for southeast Wyoming generation resources to be transferred to PacifiCorp customers in Utah and throughout the Company's service area. If one path is out of service, the other path will provide backup transmission service capability, within the limits of the remaining path. These parallel paths will improve system reliability by reducing the number and magnitude of transmission schedule reductions during line outage conditions.

Q. Please describe the economic dispatch benefits of Gateway South in more detail.

A. As I explained earlier in my testimony, Gateway South, together with Gateway West Segment D.1, will allow the Company to interconnect an additional 2,030 MW of generation resources in eastern Wyoming and increase the system transfer capability by approximately 875 MW from the Windstar/Dave Johnston area south to the Shirley Basin/Aeolus area, which will create approximately 1,700 MW of incremental transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover). Connecting into the Mona/Clover market hub provides the Company additional flexibility to use least-cost resources from eastern Wyoming or Utah to serve Utah customer load. The increased capacity also provides improved access to existing generation resources, and increased opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other energy imbalance market participants' systems, as noted by Mr. Link.

Q. Please describe how Gateway South can provide cost savings in the form of reduced energy and capacity losses.

A. Reduced energy and capacity losses on the transmission system have the potential to provide significant cost savings over time. Generally, the addition of a new transmission path in parallel with existing lines, like Gateway South, will reduce the energy and capacity losses by reducing the impedance of the transmission system.

Reduced line losses mean more efficient delivery of energy and capacity at reduced costs.

Q. Please describe the anticipated improvements in Wyoming and Utah reliability.

A. Gateway South will enhance the reliability of the Wyoming and Utah transmission system by providing increased system strength (fault duty) and improved transmission voltage performance during both steady-state and line outage conditions. This Wyoming transmission reliability enhancement is as a result of the Aeolus – Clover 500-kV transmission line linking the two geographically separate areas of eastern Wyoming and central Utah. The project also enhances Wyoming transmission reliability during Aeolus – Bridger/Anticline line outage conditions as Gateway South provides an alternative path for transferring the remaining inadvertent flows. Gateway South can enhance reliability well beyond any one state's borders. Gateway South creates a potential future high voltage source and power delivery option to meet the projected oil expansion and corresponding load growth in eastern Utah (Ashley and Vernal area). The interconnected nature of the line will improve transmission reliability of both eastern Utah and central Utah due to the line linking the two geographical separate areas of eastern Wyoming and central Utah. If the line is ultimately connected to eastern Utah communities, the Gateway South project would provide another direct load center to the abundant and economic renewable resources located within Wyoming.

Q. Has Gateway South been recognized as providing reliability benefits to the broader Western Interconnection?

A. Yes. Gateway South has undergone an extensive process to be formally included in WECC path rating studies, which was a critical milestone for the project, and one that can only occur if a new transmission facility can, at a minimum, reliably operate at its approved rating without negatively impacting other neighboring systems. Gateway South is not only considered fully reliable under this standard, but regarded as an important transmission project that is necessary to support the long-term transmission expansion planning established in the Western Interconnection plans and in the most recent Northern Tier Transmission Group – Regional Transmission Plan.[15] Additionally, through the coordination process established by the Western Planning Regions, including Northern Tier Transmission Group ("NTTG"), the California Independent System Operator, ColumbiaGrid and WestConnect, Gateway South has been included in each of the Western Planning Regions analysis efforts—providing a complete understanding of its reliability benefits to the broader Western Interconnection.

Q. What is involved in the WECC path rating study process?

A. The WECC path rating studies follow a three-phase process established by the Planning Coordination Committee ("PCC"), the predecessor to the existing Reliability Assessment Committee ("RAC"), that uses peer review study groups, made up of the project sponsor and other interested WECC members, to establish a path rating for a

[15] Since the issuance of the Norther Tier Transmission Group ("NTTG") 2018-2019 Final Regional Transmission Plan in the fourth quarter of 2019, NTTG and ColumbiaGrid regional planning organizations merged into a single regional planning organization called NorthernGrid. NorthernGrid will address regional planning activities for the northern portion of the Western Interconnection required under FERC Order No. 1000.

given transmission path or set of transmission paths, which may exhibit simultaneous interactions with each other. Path rating studies use a transmission model of the Western Interconnection and will take multiple months to evaluate the performance of the new transmission facilities and to demonstrate that the proposed transmission project will have no negative impacts on previously established transmission path ratings. The path ratings that are established following this process represent the "Maximum Path Transfer Capability" of a transmission path.

Once projects complete the second phase of the path rating studies, they are granted an "Accepted" rating and placed in Phase 3 (construction phase) status. After the Accepted status is granted, other projects currently going through the WECC path rating process must recognize the project in their studies and cannot negatively impact the path rating for the project.

Q. Please describe the WECC path rating study process for the Gateway South.

A. Gateway South has been included in the WECC's Three Phase Rating Process and approved by WECC for Phase 3-Construction Phase status as part of the overall Energy Gateway project. The Aeolus South transmission path rating studies, evaluating Gateway South, have completed the Three Phase Rating Process and Gateway South was granted Phase 3 status on December 16, 2010. This WECC approval is necessary because it allows the Company to interconnect Gateway South to the wider transmission system in the area, which is part of the Western Interconnection, and to reliably operate the project at their approved ratings.

Q. Has Gateway South been included in Utah-specific transmission planning assessments?

A. Yes. On January 21, 2021, Energy Strategies, on behalf of the Utah Office of Economic Development, released its "Utah Transmission Study: A Study of the Options and Benefits to Unlocking Utah's Resource Potential" (hereinafter, the "Utah Study").[16] The Utah Study explains that, "[d]uring the 2019 Utah Legislative Session, Senate Bill 3 allocated funds for an analysis of the Utah electrical transmission grid" and that the "goal of the study was to identify transmission constraints to accessing Utah's resource potential and to provide options to address them."[17] According to the study, "Unlocking opportunities for continued investment in a broad suite of generation and storage technologies will leave Utah well positioned to compete in Western electricity markets while also providing its customers with low-cost and reliable power."[18]

Q. How did the Utah Study account for Gateway South?

A. For purposes of the study, Gateway South was assumed to be in service.[19] Therefore, the results of the study rely on the transmission benefits and increased capacity provided by Gateway South as a baseline assumption. Even after assuming Gateway South was in service, the Utah Study concluded that additional transmission build-out is likely to be required to meet future Utah loads:

> Transmission expansion along Utah's north-south backbone system will be required to address the grid constraints and to support the levels of generation and storage buildout envisioned in this study. This finding is based on power system modeling that confirms that Utah's current and planned grid is unlikely to

[16] The study is available here: https://energy.utah.gov/wp-content/uploads/Utah-Transmission-Study-Summary.pdf
[17] Utah Study at 1.
[18] Utah Study at 3.
[19] Utah Study at 18-19.

> be able to accommodate forecasted resource deployment without transmission system upgrades. While perhaps viable for specific projects, non-wires solutions were not effective at providing the required magnitude of transfer capability. Therefore, new transmission is likely to be required.[20]

ALTERNATIVE EVALUATION

Q. How was the configuration and voltage level of Gateway South determined?

A. Due to the broad scope and nature of the Energy Gateway Projects, a wide range of transmission configurations and voltage levels (from 345-kV up to 765-kV) were initially considered. Ultimately, the prevalence of 500-kV transmission in the Western Interconnection, size and location of future resources, level of projected transfers, and transmission loss reduction were determining factors in selecting the voltage class for Gateway South.

Q. Has there been any independent analysis performed to confirm the configuration and voltage level of Gateway South?

A. Yes. During the NTTG 2018–2019 biennial study cycle, Deseret Power, on behalf of itself and four other Utah stakeholders, requested an economic study be performed to evaluate up to two 345-kV transmission lines as a lower-cost alternative to the 500-kV Gateway West and Gateway South lines.

Based on this request, an economic study was performed by the Planning Committee that demonstrated acceptable system performance for the proposed 345-kV lines. However, additional production cost model ("PCM") simulations indicated that the 345-kV lines would have lower overall transmission capacity than the planned 500-kV transmission. This capacity limitation would result in increased flows on

[20] Utah Study at 59-60.

transmission exiting Wyoming and would force generation to increase in Utah in the PCM simulations, dispatching it without consideration of economics.

In addition to the economic and capacity limitations, securing permits and rights-of-way for the two proposed 345-kV lines could require an additional 12-to-15 years. The Planning Committee also noted that PacifiCorp already secured all rights-of-way and was currently building the Aeolus-to-Anticline 500-kV transmission system in Wyoming, scheduled for energization in 2020. Due to these limitations and because the proposed 345-kV option has no sponsor, the project was not considered in the NTTG Regional Transmission Plan for the 2018–2019 biennial study cycle.

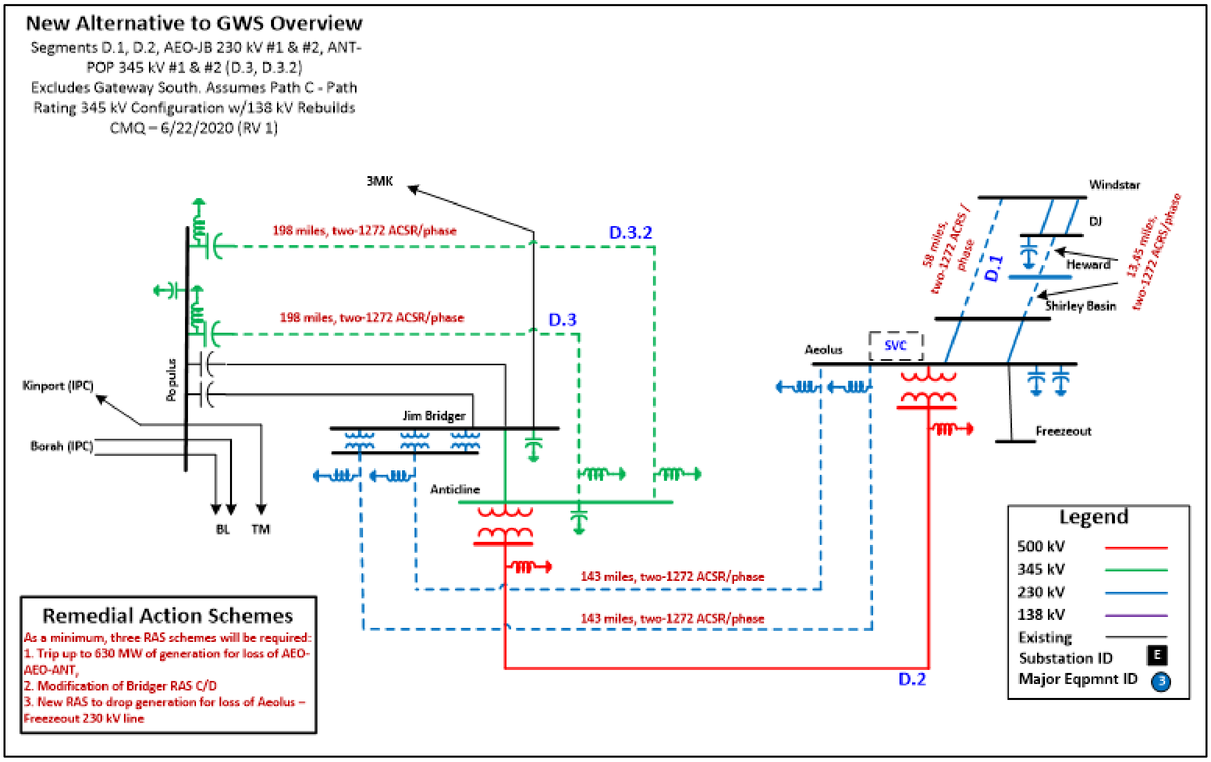
Q. Subsequent to the NTTG analysis of a 345-kV alternative to the Transmission Projects, has any additional analysis been performed?

A. Yes. As discussed by Mr. Link, when evaluating the Company's 2019 IRP, the Commission was concerned that that "PacifiCorp excluded from its modeling a potential alternative transmission expansion case evaluated by NTTG in its 2018-2019 Regional Transmission Plan that demonstrated sufficient merit to warrant PacifiCorp's further study."[21] The Commission reiterated this concern when approving the 2020AS RFP.[22] In response, PacifiCorp performed follow-up analysis that evaluated both performance and cost differences between Gateway South and the proposed 345-kV option presented as an alternative study in the NTTG plan.

[21] *PacifiCorp's 2019 Integrated Resource Plan*, Docket No. 19-035-02, Order at 22 (May 13, 2020).
[22] *Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals*, Docket No. 20-035-05, Order Approving 2020 All Source RFP at 14-15 (July 17, 2020).

Q. Was the system performance significantly different between the two configurations?

A. Yes. Technical studies demonstrated that by replacing Gateway South with 345-kV/230-kV alternative transmission improvements between Aeolus – Anticline – Populus, as illustrated in Figure 5 below, eastern Wyoming wind generation additions would have to be significantly reduced from 1,882 MW to 1,441 MW. For this alternative transmission configuration, transfers from Wyoming – (Idaho) – Utah would be reduced from 1,700 MW to 814 MW due to Path C (Idaho to Utah) transmission path limitations. During the analysis, some Path C 2,250 MW transmission path restrictions specific to the underlying 138-kV system were ignored to achieve a higher rating of 2,414 MW from Idaho to Utah. Under the transfer level evaluated, all transmission paths would be near their path ratings and no thermal/voltage violations would be evident during facility outage conditions. The report identified additional transmission facilities that would be required to support generation additions and transfer level noted above were estimated to cost $1.539 billion to construct.



PERMITTING STATUS

Q. Please describe all of the permits that are required to facilitate the construction of Gateway South.

A. A list of the required Federal, State and local permits is included with the Application as Exhibit 1.

Q. Has the Company received all the required permits?

A. The Company has received many of the required permits and will obtain all permits ahead of construction. Many of the construction related permits will be obtained by the construction contractor. The status of each permit is included in Exhibit 1.

RECOMMENDATION AND CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission approve the Company's Application. Gateway South will provide substantial benefits to its customers and is necessary and in the public interest. Based on this conclusion, I recommend that the Commission grant the Company a CPCN for Gateway South by June 1, 2022.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RAV-1)
Docket No. 21-035-54
Witness: Richard A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

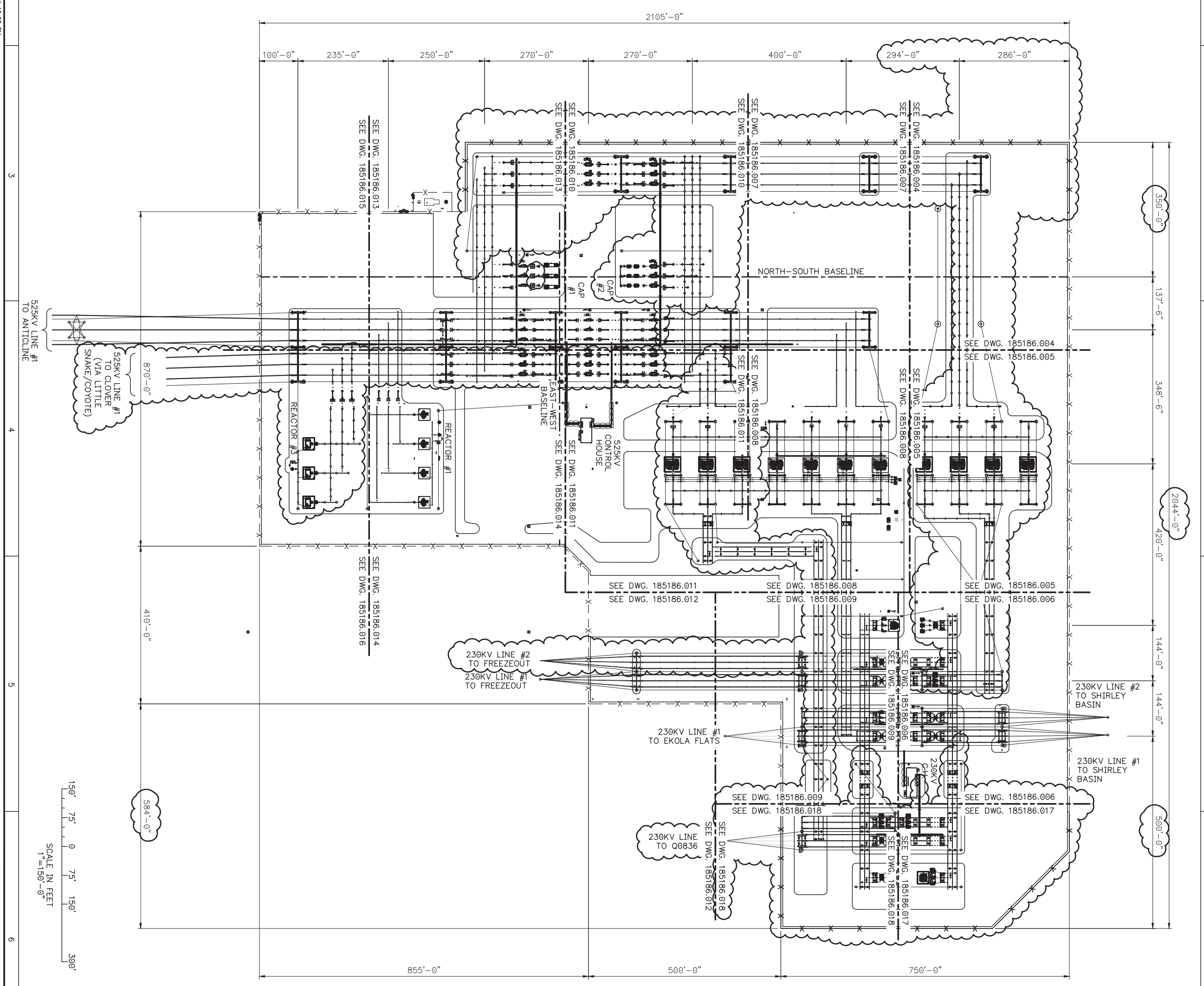
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Richard A. Vail

One-Line Diagrams

October 2021

Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 1 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



REFERENCE DRAWINGS

185183 DRAWING LIST
185184 CABLE LIST
185185 BILL OF MATERIALS
185187 PLANS & ELEVATIONS
185188 BUS CONNECTION DETAILS
185189 CONDUIT PLAN
185191 GROUNDING PLAN
185200 FIBER CABLE ROUTE
185202 LIGHTNING PROTECTION PLAN
185214 FOUNDATION PLAN

PRELIMINARY
HOLD FOR FINAL DRAWING

AEOLUS SUBSTATION
CARBON COUNTY, WYOMING
GENERAL PLAN
KEY SHEET

REVISION 1B | 185186.003 | SHEET 3

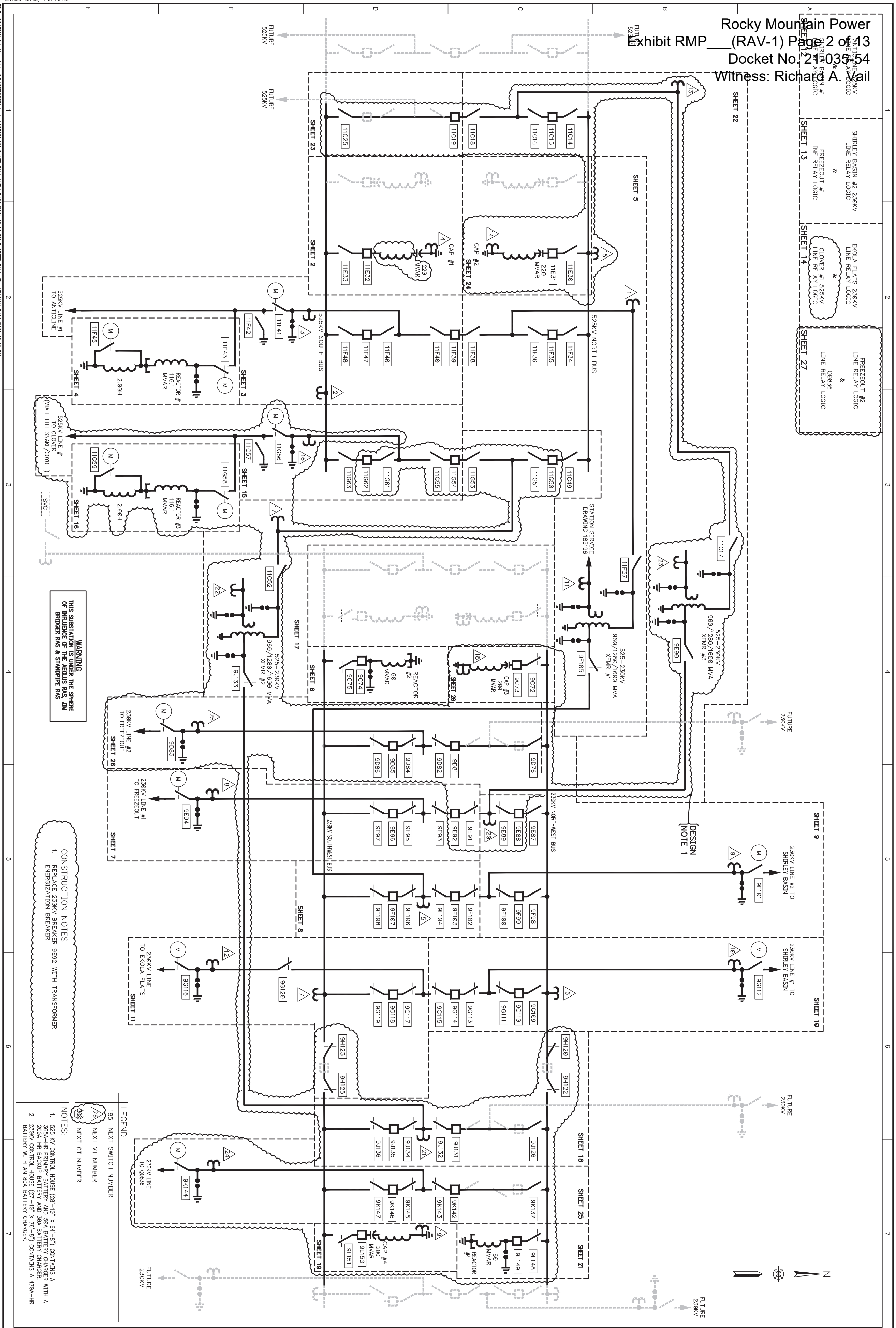
ELECTRICAL

PROJ/ER# 10067811		DISCIPLINE ENG. SEAN CRAKER/BMcD
PL# 576026		
DATE: 10/03/2019		PROJECT ENG. SEAN CRAKER/BMcD
ENG.S. CRAKER/BMcD	DES. S. CRAIG/BMcD	
DR. J. WERNER/BMcD	CH. M. EMMERLING/BMcD	APPROVAL ENG. SEAN CRAKER/BMcD
SCALE: 1"=150'-0"		

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
1B	07/30/21	WO# 10044401 ADDED 525/230KV XFMR 2 & 3, 230KV CAP BANK 1 & 2, 525KV CAP BANK 2 & REACTOR 2, 525KV LINE TO CLOVER; ISSUED FOR REVIEW #2	B. CULTON/PEI	N. DAVIS/PEI	D. JONES/PEI	

REVISED 05/02/14 D. HURLEY



AEOLUS SUBSTATION
CARBON COUNTY, WYOMING
ONE LINE DIAGRAM
KEY SHEET

REVISION 1B | 185281.001 | SHEET 1 OF 27

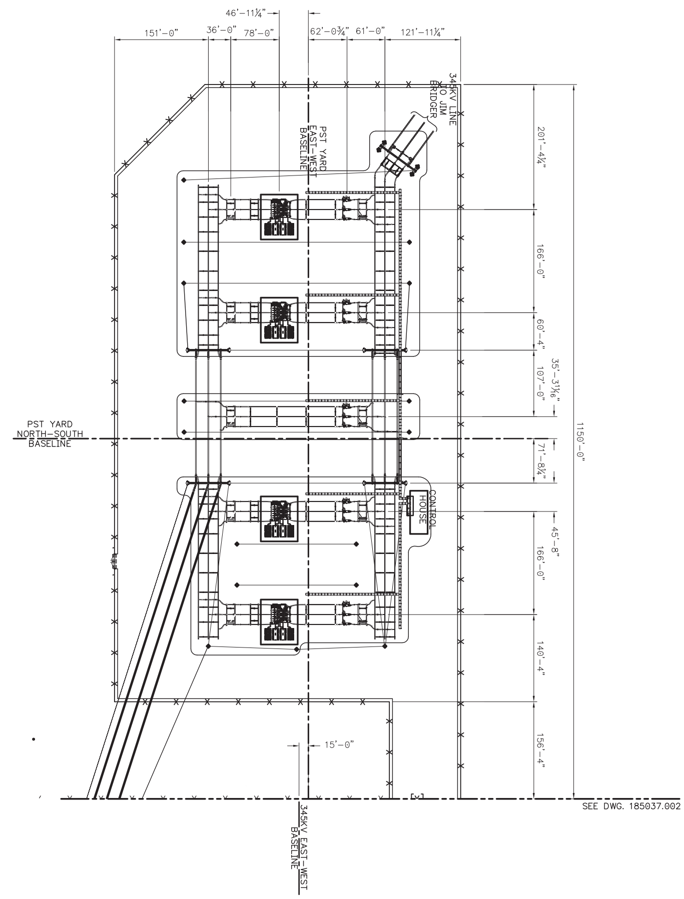
PROTECTION & CONTROL

PROJ/ER# 10067811	DISCIPLINE ENG. SEAN CRACKER/BMcD
PL# 576026	
DATE: 01/10/2020	PROJECT ENG. SEAN CRACKER/BMcD
ENG. S. CRACKER/BMcD	DES. S. CRACKER/BMcD
DR. A. BERRY/BMcD	CH. E. EMMERLING/BMcD
SCALE: NONE	APPROVAL ENG. SEAN CRACKER/BMcD

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
1B	07/30/21	WO# 10044401 EXPANDED 230KV AND 525KV YARD; ISSUED FOR REVIEW #2	A. LARSON/PEI	I. GALLEGOS/PEI	B. PERRY/PEI	

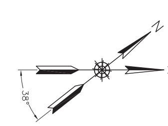
Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 3 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



PRELIMINARY
NOT FOR CONSTRUCTION
09/08/2021

PRELIMINARY

SCALE IN FEET
1"=100'-0"



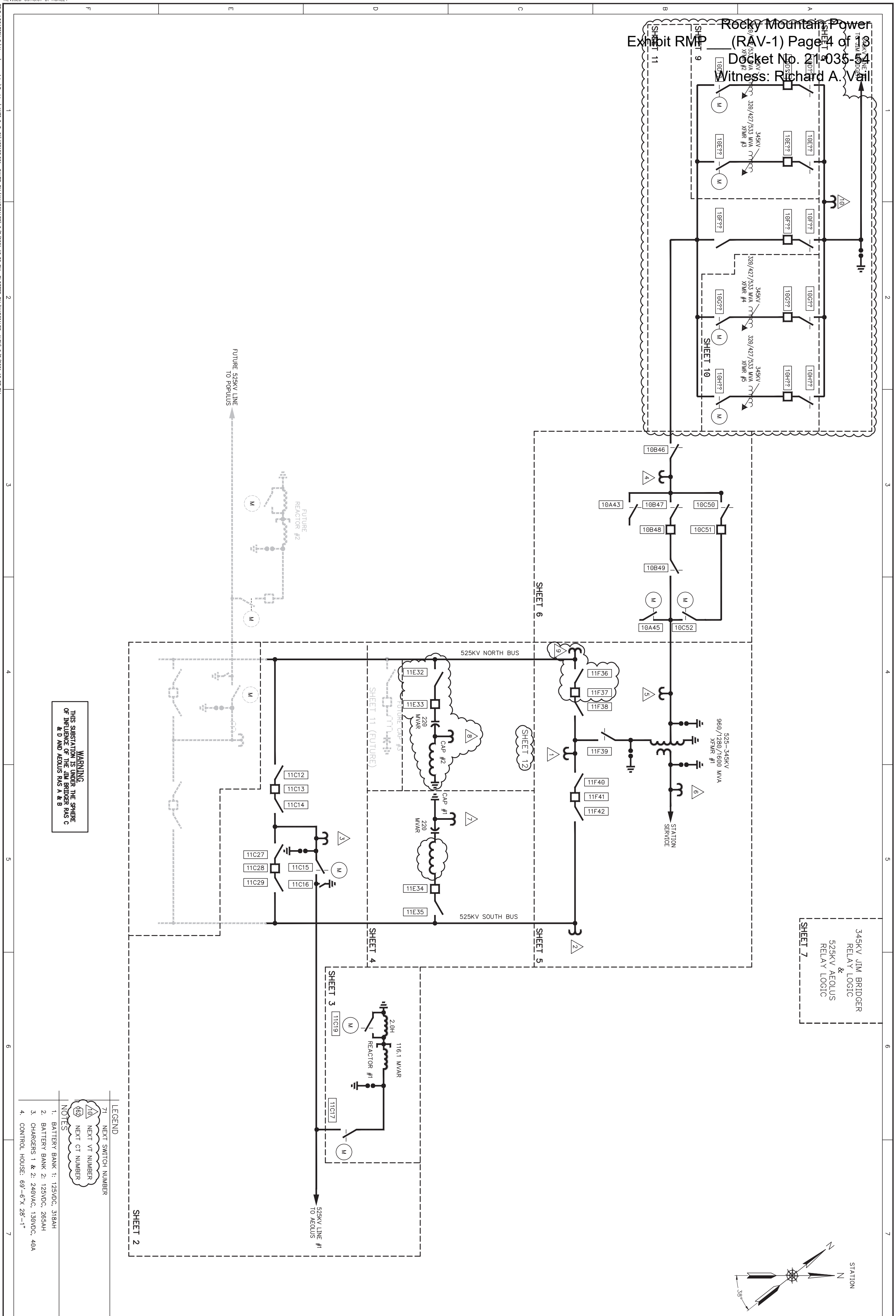
ANTICLINE SUBSTATION SWEETWATER COUNTY, WYOMING GENERAL PLAN ULTIMATE PLANNED DEVELOPMENT	ELECTRICAL	
REVISION 0A	PROJ/ER# 10073097	DISCIPLINE ENG. RAYMOND E. MEADS/PEI
185037.011	PL# 540071	PROJECT ENG. BARBARA A. CULTON/PEI
SHEET 11	ENG. R. BARATI/PEI; DESM. RODRIGUEZ/PEI	APPROVAL ENG. RAYMOND E. MEADS/PEI
	DR. M. RODRIGUEZ/PEI; CH.	
	SCALE: 1"=100'-0"	

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
0A		WO# 10073097 ISSUED FOR REVIEW #2	R. BARATI/PEI	M. RODRIGUEZ/PEI		

Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 4 of 13
Docket No. 21-035-54
Witness: Richard A. Vail

REVISED 09.18.07 D. HURLEY



ANTICLINE SUBSTATION
SWEETWATER COUNTY, WYOMING
ONE LINE DIAGRAM
KEY SHEET

REVISION 1B | 185128.001 | SHEET 1 OF 12

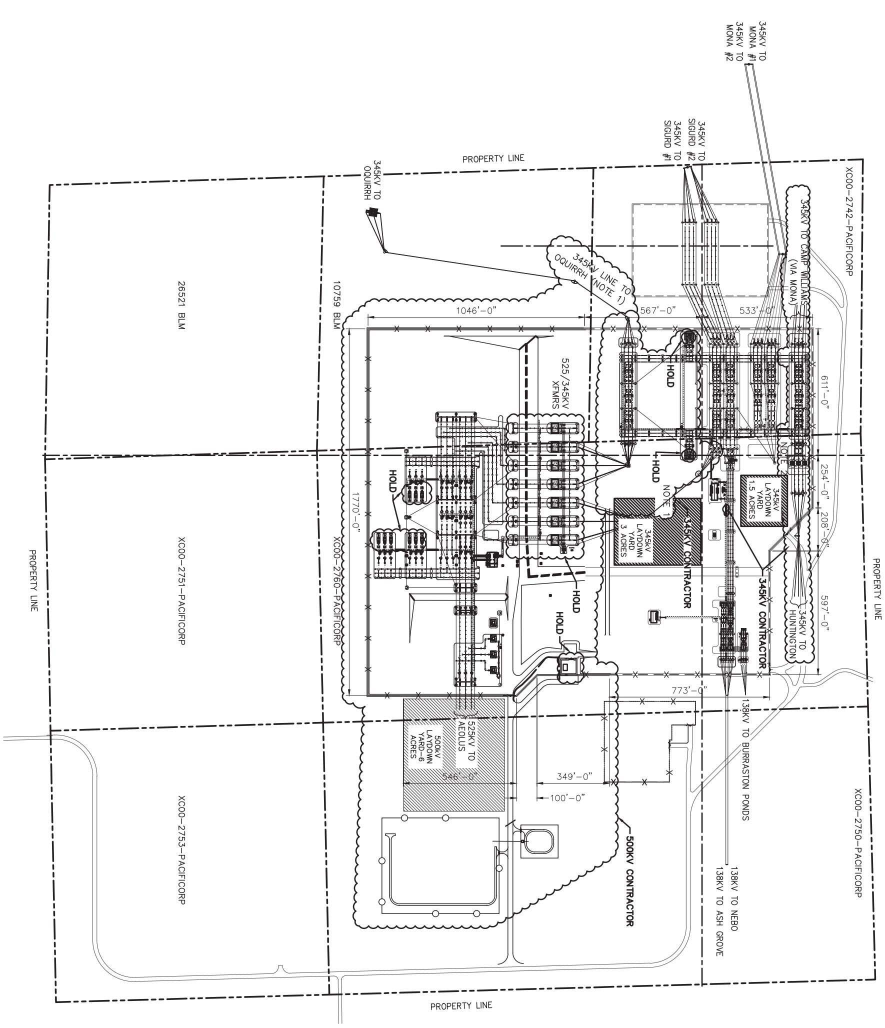
PROTECTION & CONTROL

PROJ/ER# 10067812		DISCIPLINE ENG. ANTONY ALAPATT/BMcD	
PL# 540071			
DATE: 01/24/2020		PROJECT ENG. ANTONY ALAPATT/BMcD	
ENG. A. ALAPATT/BMcD	DES. J. MEYER/BMcD		
DR. J. WERNER/BMcD	CH. C. MA/BMcD	APPROVAL ENG. SEAN CRAKER/BMcD	
SCALE: NONE			

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
1B	04/12/21	WO# 10073097 ISSUED FOR REVIEW #1	F. UNDERWOOD/PEI	A. MARCIALES/PEI	B. PERRY/PEI	

Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 5 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



PRELIMINARY
NOT FOR CONSTRUCTION
09/08/2021

SCALE IN FEET
1"=300'-0"

LEGEND
SUBSTATION BASE LINE.
PROPERTY LINES.

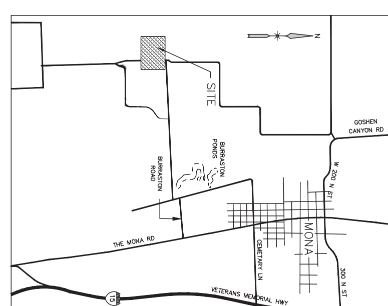
NOTES
1. THE 345KV OQUIRRH LINE WILL BE RELOCATED TO SOUTHWEST CORNER OF THE 345KV YARD AND THE EXISTING BAY UPGRADED TO 4,000 AMPS PRIOR TO CONNECTING THE 525/345KV TRANSFORMER #3 TO THE EXISTING 345KV OQUIRRH POSITION.
2. RELOCATED 345KV REACTORS FROM MONA.

REFERENCE DRAWINGS
132506 ONE LINE DIAGRAMS
132314 GRADING PLANS
132667 FOUNDATION PLANS
132320 PLANS AND ELEVATIONS
132322 GROUNDING PLANS
132324 CONDUIT AND CABLE PLANS
132326 CABLE TRENCH PLANS
132328 LIGHTING PLAN

PRELIMINARY

VICINITY MAP
SCALE: NTS

LONGITUDE: 111° 53' 39" W
LATITUDE: 39° 47' 23" N
ELEVATION: 5046'



NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
1A	07/23/20	WO# ISSUED FOR PRELIMINARY REVIEW	PEI	DLJ	SS	
1B	07/09/21	WO# 10044402 ADDED 345KV AND 500KV EXPANSION; ISSUED FOR DESIGN REVIEW #2	B. CULTON/PEI	D. JONES/PEI	S. SORVALA/PEI	

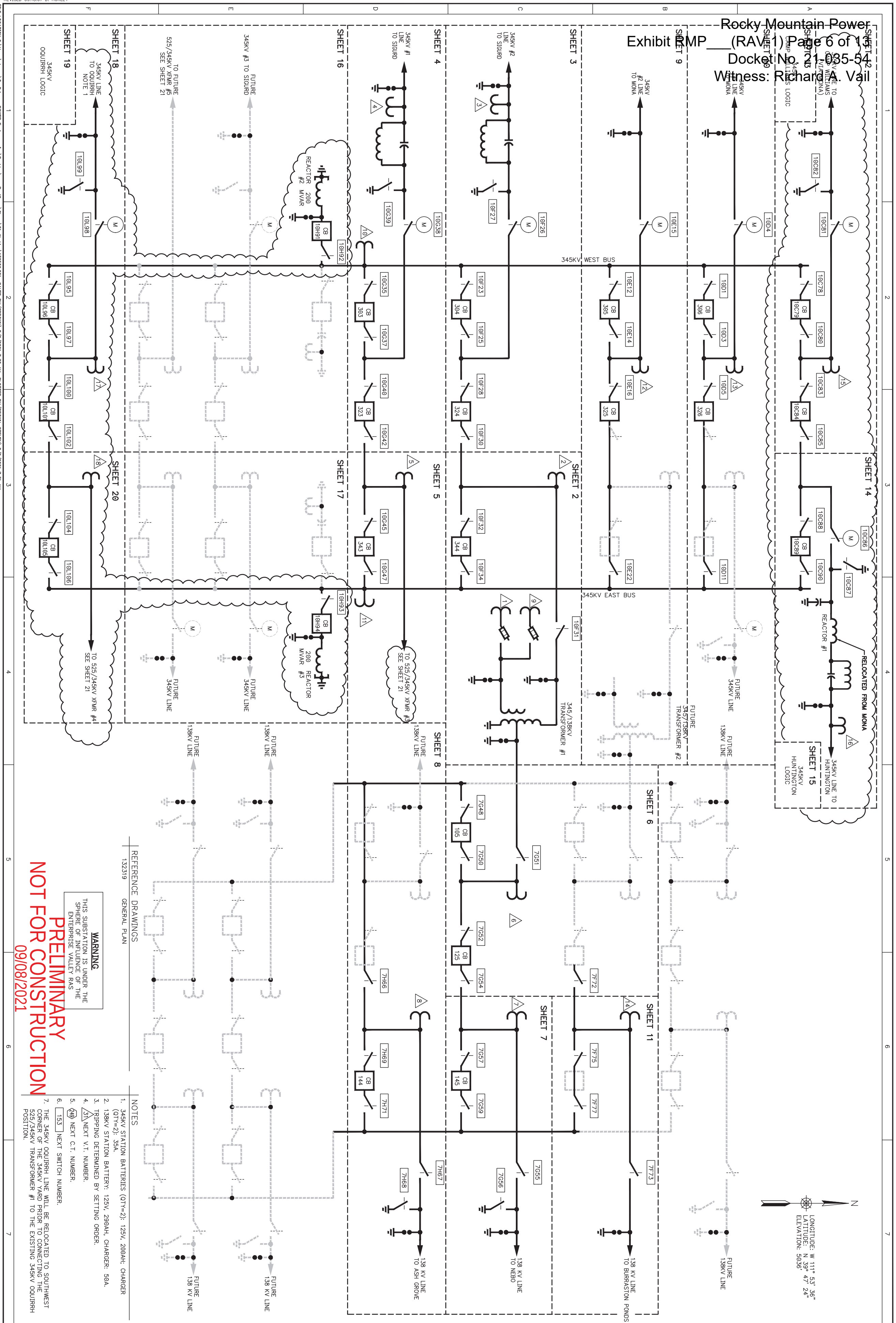
CLOVER SUBSTATION
JUAB COUNTY, UTAH
GENERAL PLAN
PROPERTY AND TRANSMISSION LAYOUT

REVISION 1B | 132319.001 | SHEET 1 OF 18

ELECTRICAL

PROJ/ER# 10039661		DISCIPLINE ENG. TYLER MCCREADY/SCI
PL# 086233		
DATE: 01/26/2012		PROJECT ENG. MIKE MUHLENHAUPT/SCI
ENG.T. MCCREADY/SCI	DES. T. MCCREADY/SCI	
DR. M. ANDREASEN/SCI	CH. M. MUHLENHAUPT/SCI	APPROVAL ENG. MIKE MUHLENHAUPT/SCI
SCALE: 1"=300'-0"		

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY



NOTES
1. 345KV STATION BATTERIES (QTY=2): 125V, 200AH; CHARGER (QTY=2): 35A.
2. 138KV STATION BATTERY: 125V, 290AH; CHARGER: 50A.
3. TRIPPING DETERMINED BY SETTING ORDER.
4. NEXT V.T. NUMBER.
5. NEXT C.T. NUMBER.
6. 153 NEXT SWITCH NUMBER.
7. THE 345KV OQUIRRH LINE WILL BE RELOCATED TO SOUTHWEST CORNER OF THE 345KV YARD PRIOR TO CONNECTING THE 525/345KV TRANSFORMER #1 TO THE EXISTING 345KV OQUIRRH POSITION.

CLOVER SUBSTATION
JUAB COUNTY, UTAH
ONE LINE DIAGRAM
KEY SHEET

REVISION 3B | 132506.001 | SHEET 1 OF 29

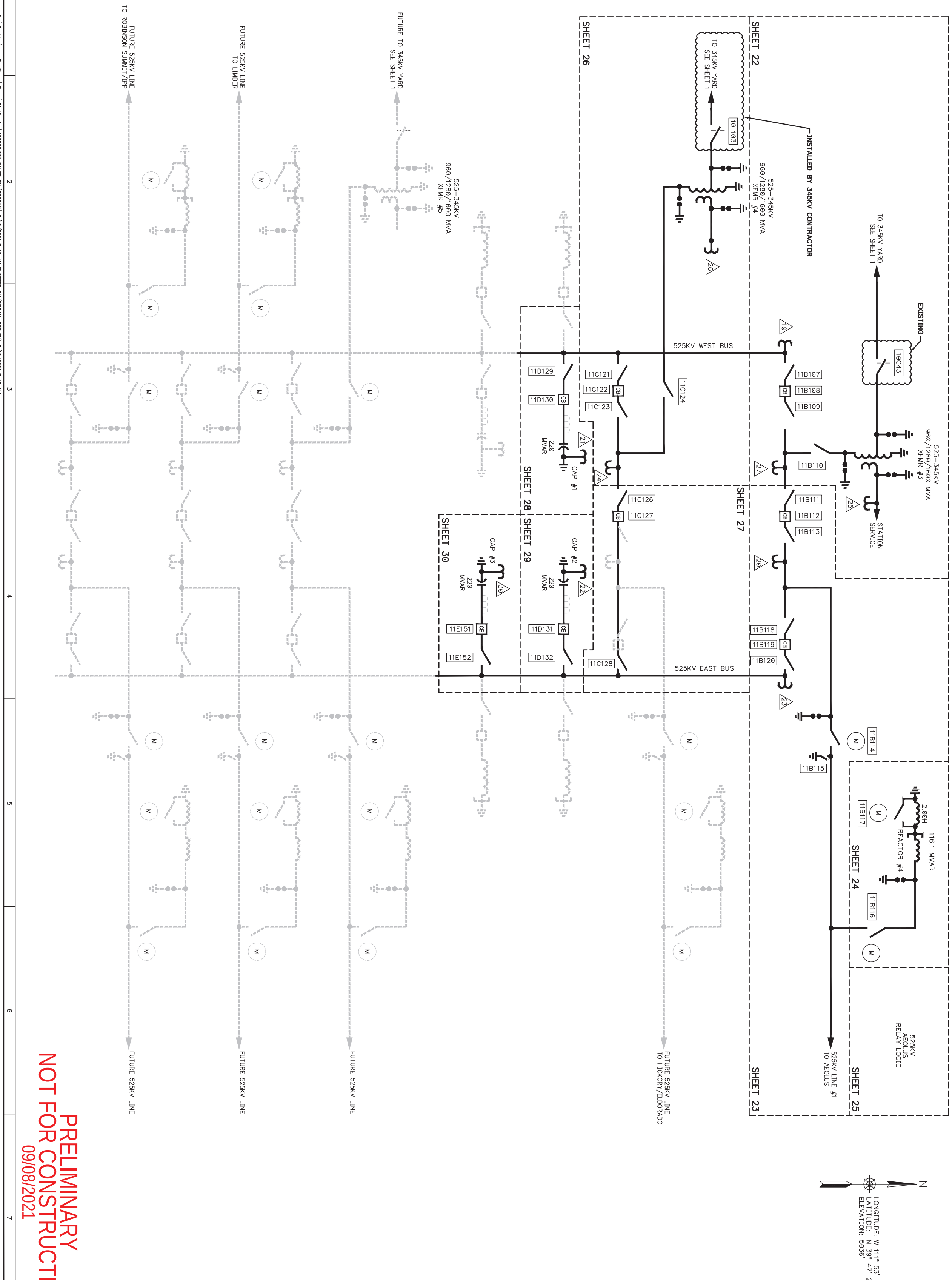
PROTECTION & CONTROL

PROJ/ER# 10039661/10039662	DISCIPLINE ENG. NICOLE PADGETT/SCI
PL# 086233	
DATE: 01/26/2012	PROJECT ENG. PHIL SCHULZ/SCI
ENG. N. PADGETT/SCI / DES. N. PADGETT/SCI	
DR. N. PADGETT/SCI / CH. P. SCHULZ/SCI	APPROVAL ENG. MIKE MUHLENHAUPT/SCI
SCALE: NONE	

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
1	10/03/14	WO# 10053252 ADDED CB 144, SWITCHES, ARRESTORS & CCVT FOR NEW 138 KV LINE, & ADDED SHEET 11	T. PAYNE/SCI	A. BARRY/SCI	P. SCHULZ/SCI	M. MUHLENHAUPT/SCI
2	03/25/20	WO# 10068918 ADDED ENTERPRISE VALLEY RAS	R. CALLES/PEI	A. FRUCTOSO/PEI	P. SCOGGINS/PEI	P. RICKER/PEI
3A	07/23/20	WO# 10044402 ISSUED FOR REVIEW #1	E. GRAVES/PEI	S. BROWN/PEI	B. PERRY/PEI	
3B	07/16/21	WO# 10044402 ISSUED FOR REVIEW #2	E. GRAVES/PEI	S. BROWN/PEI	S. SIBSON/PEI	

REVISED 05/02/14 D. HURLEY



PRELIMINARY
NOT FOR CONSTRUCTION
09/08/2021

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
0A	07/23/20	WO# 10044402 ISSUED FOR REVIEW #1	E. GRAVES/PEI	S. BROWN/PEI	B. PERRY/PEI	
0B	07/09/21	WO# 10044402 ISSUED FOR REVIEW #2	E. GRAVES/PEI	S. BROWN/PEI	S. SIBSON/PEI	

CLOVER SUBSTATION
JUAB COUNTY, UTAH
ONE LINE DIAGRAM
525KV KEY SHEET

REVISION 0A | 132506.021 | SHEET 21

PROTECTION & CONTROL

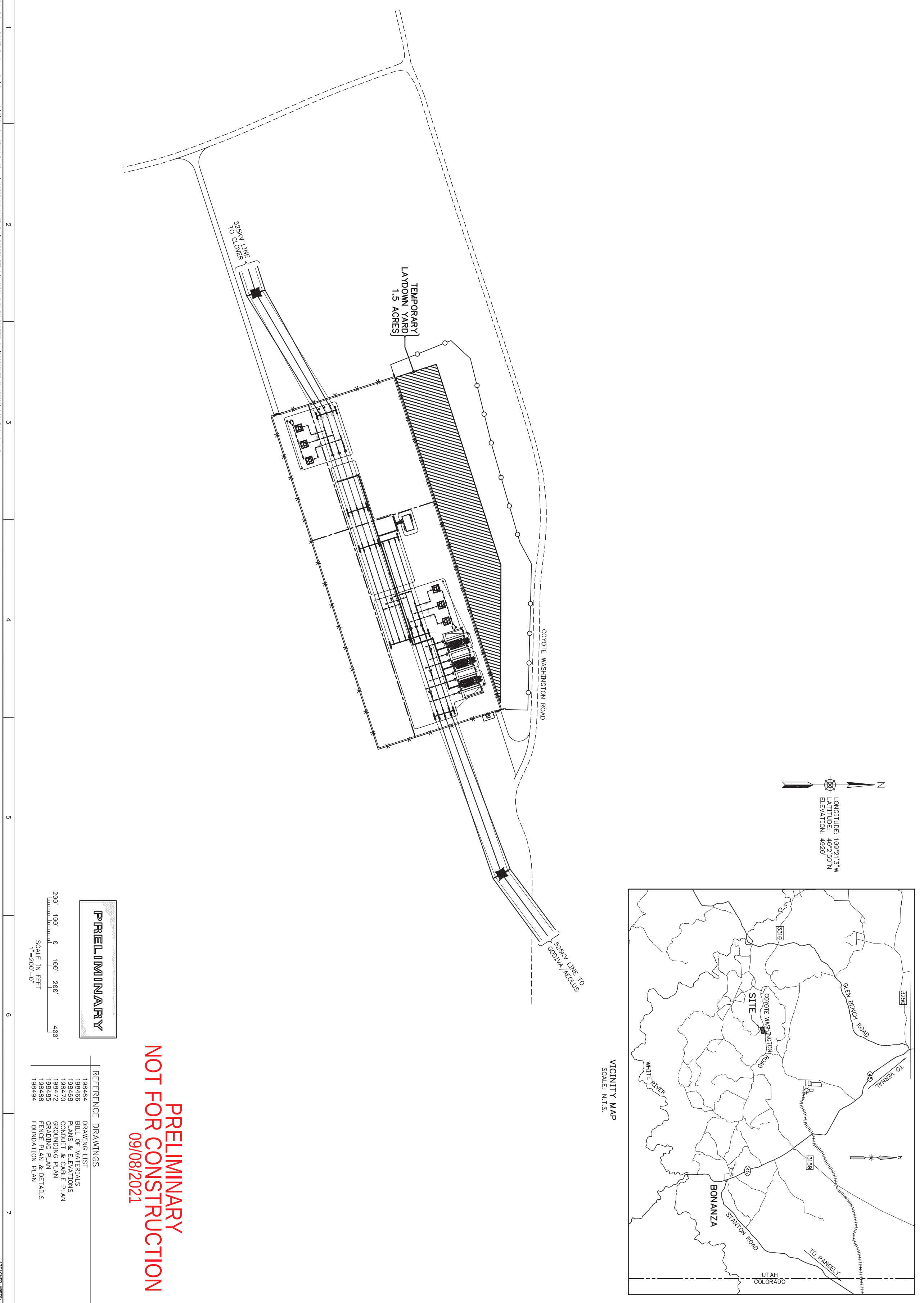
PROJ/ER# 10044402
PL# 086233
DATE:
ENG. E. GRAVES/PEI | DES.
DR. L. AXEL/PEI | CH.
SCALE: NONE

DISCIPLINE ENG.
PROJECT ENG. B. CULTON/PEI
APPROVAL ENG.

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

REVISED 05/02/14 D. HURLEY

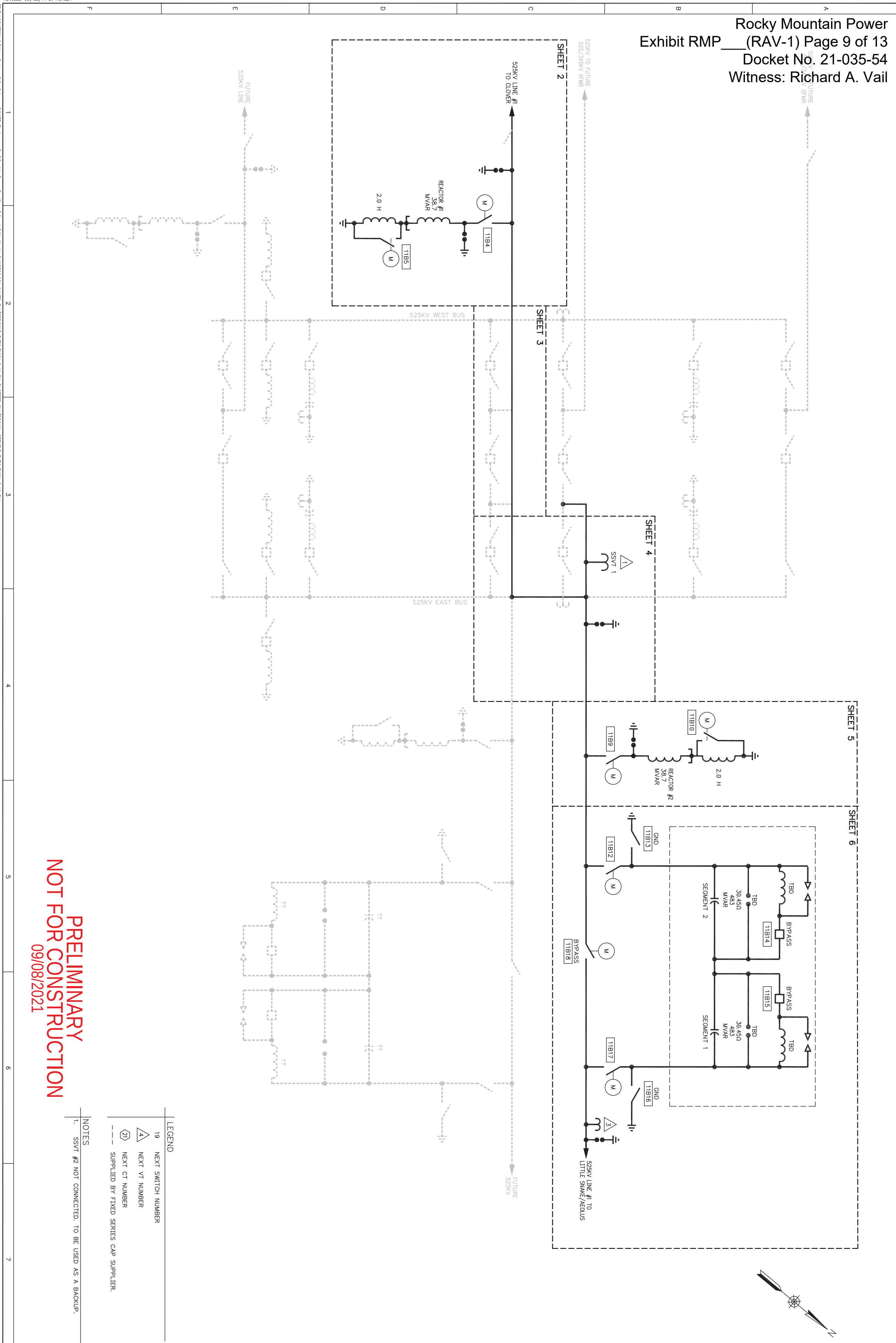
Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 8 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



COYOTE SUBSTATION UINTAH COUNTY, UTAH GENERAL PLAN PROPERTY & TRANSMISSION LAYOUT	ELECTRICAL		PACIFICORP A BERKSHIRE HATHAWAY ENERGY COMPANY
	PROJ/ER# 10044404	DISCIPLINE ENG.	
	PL# 086273		
	DATE:	PROJECT ENG. BARBARA A. CULTON/PEI	
	ENG. B. CULTON/PEI · DES. N. DAVIS/PEI		
REVISION 0B · 198467.001 · SHEET 1 OF 7	DR. N. DAVIS/PEI · CH.	APPROVAL ENG.	
	SCALE: 1"=200'-0"		

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
0A	07/31/20	WO# 10044404 ISSUED FOR REVIEW #1	B. CULTON/PEI	N. DAVIS/PEI	S. SORVALA/PEI	
0B	06/03/21	WO# 10044404 ISSUED FOR REVIEW #2	B. CULTON/PEI	N. DAVIS/PEI	S. SORVALA/PEI	

Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 9 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



LEGEND
19 NEXT SWITCH NUMBER
4 NEXT VT NUMBER
21 NEXT CT NUMBER
– – – SUPPLIED BY FIXED SERIES CAP SUPPLIER.

NOTES
1. SSVT #2 NOT CONNECTED. TO BE USED AS A BACKUP.

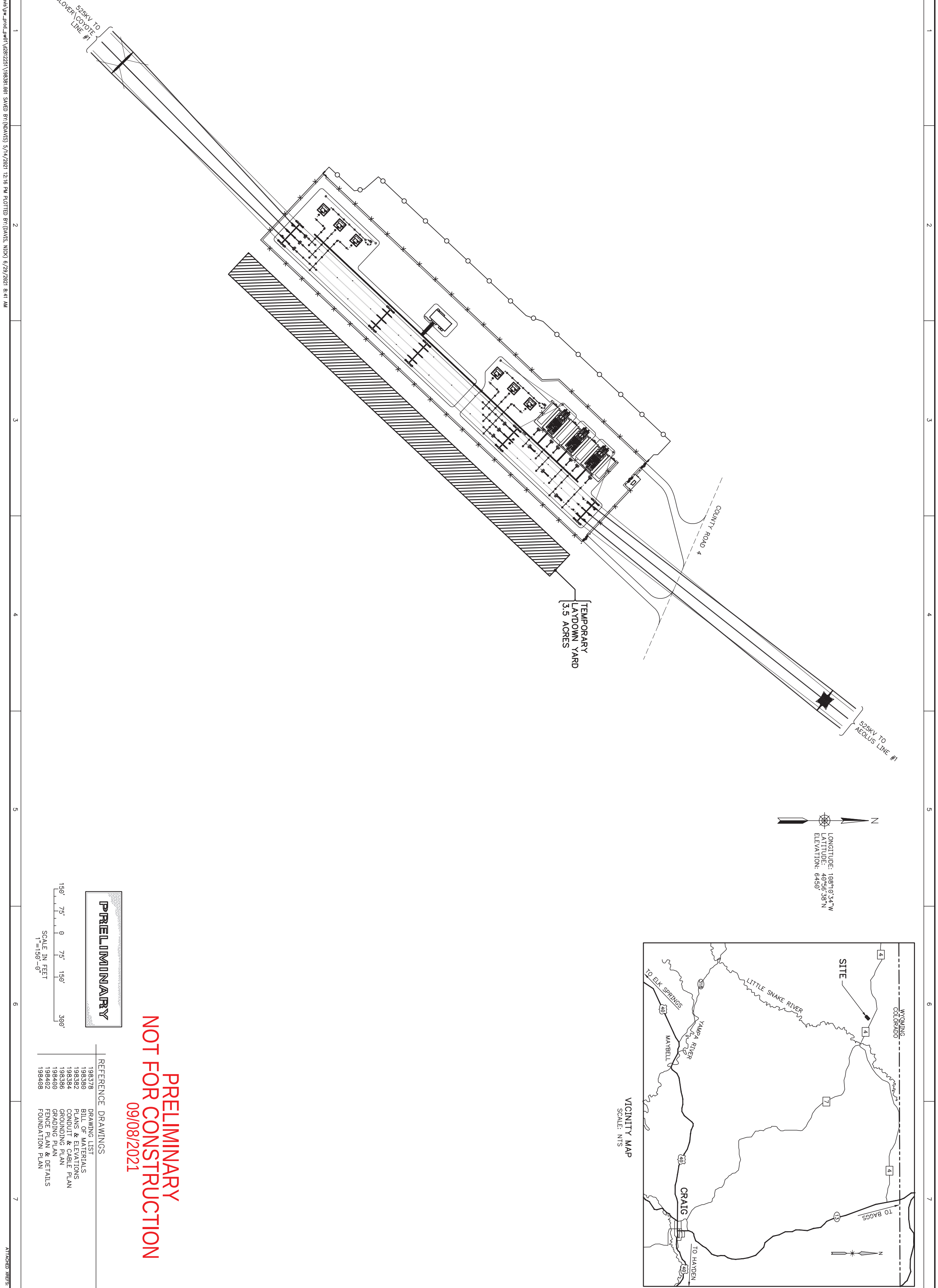
NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
0C	06/04/21	WO# 10044404 ISSUED FOR FSC BID	A. CAHOW/PEI	S. BROWN\PEI	A. SILVA/PEI	

COYOTE SUBSTATION
UINTAH COUNTY, UTAH
ONE LINE DIAGRAM
KEY SHEET

REVISION 0C — 198526.001 — SHEET 1 OF 6

PROTECTION & CONTROL
PROJ/ER# 10044404
PL# 086273
DATE:
ENG. A. CAHOW/PEI — DES. A. CAHOW/PEI
DR. S. BROWN/PEI — CH. A. SILVA/PEI
SCALE: NONE
DISCIPLINE ENG. ALEXANDER J. CAHOW/PEI
PROJECT ENG. BARBARA A. CULTON/PEI
APPROVAL ENG.

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY



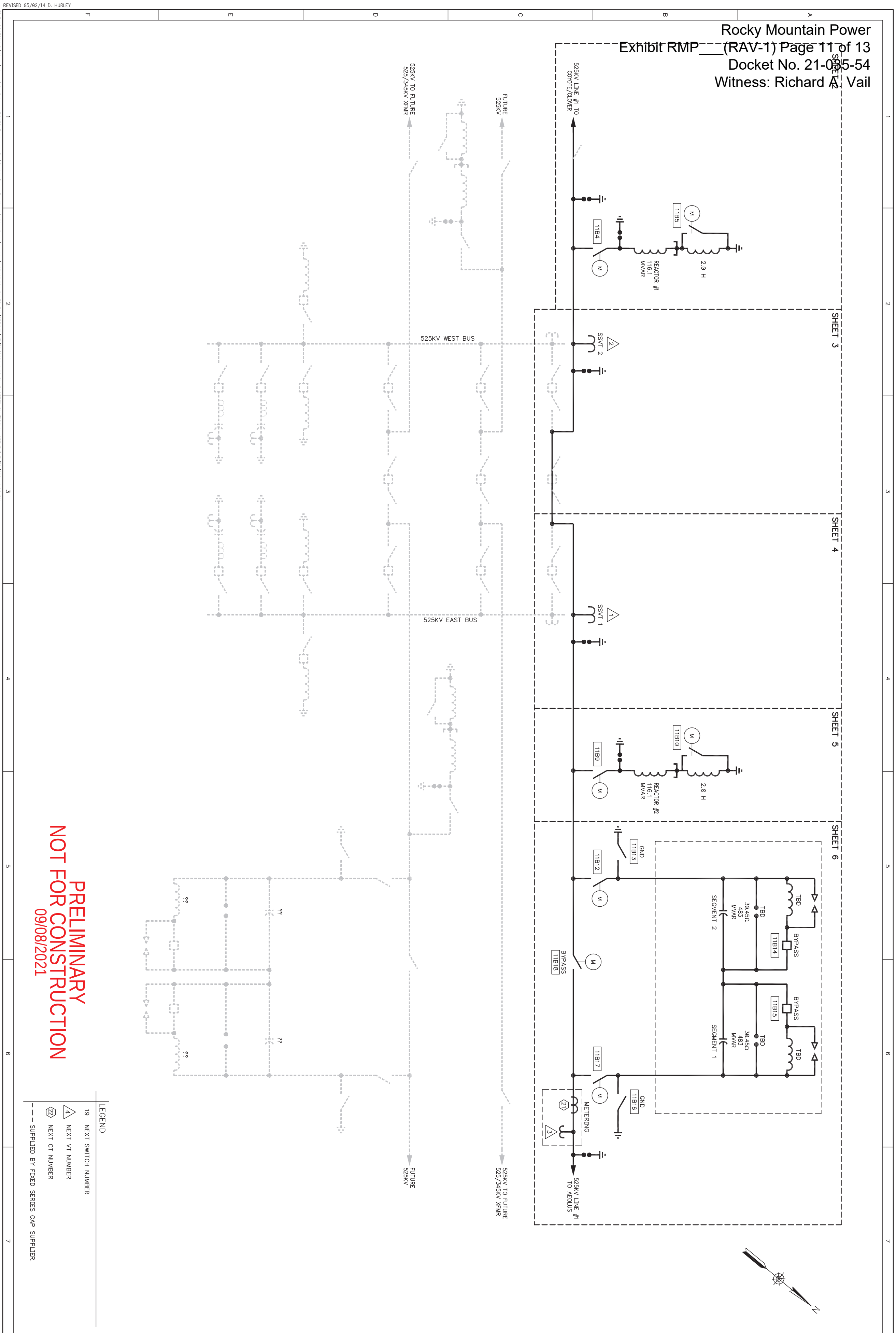
LITTLE SNAKE SUBSTATION
MOFFAT COUNTY, COLORADO
GENERAL PLAN
PROPERTY & TRANSMISSION LAYOUT

REVISION 0B — 198381.001 — SHEET 1 OF 7

ELECTRICAL
PROJ/ER# 10044403
PL# 083000
DATE:
ENG. B. CULTON/PEI — DES. N. DAVIS/PEI
DR. N. DAVIS/PEI — CH.
SCALE: 1"=150'-0"
DISCIPLINE ENG.
PROJECT ENG. BARBARA A. CULTON/PEI
APPROVAL ENG.

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
0B	05/05/21	WO# 10044403 ISSUED FOR REVIEW #2	B. CULTON/PEI	N. DAVIS/PEI	P. SCOGGINS/PEI	

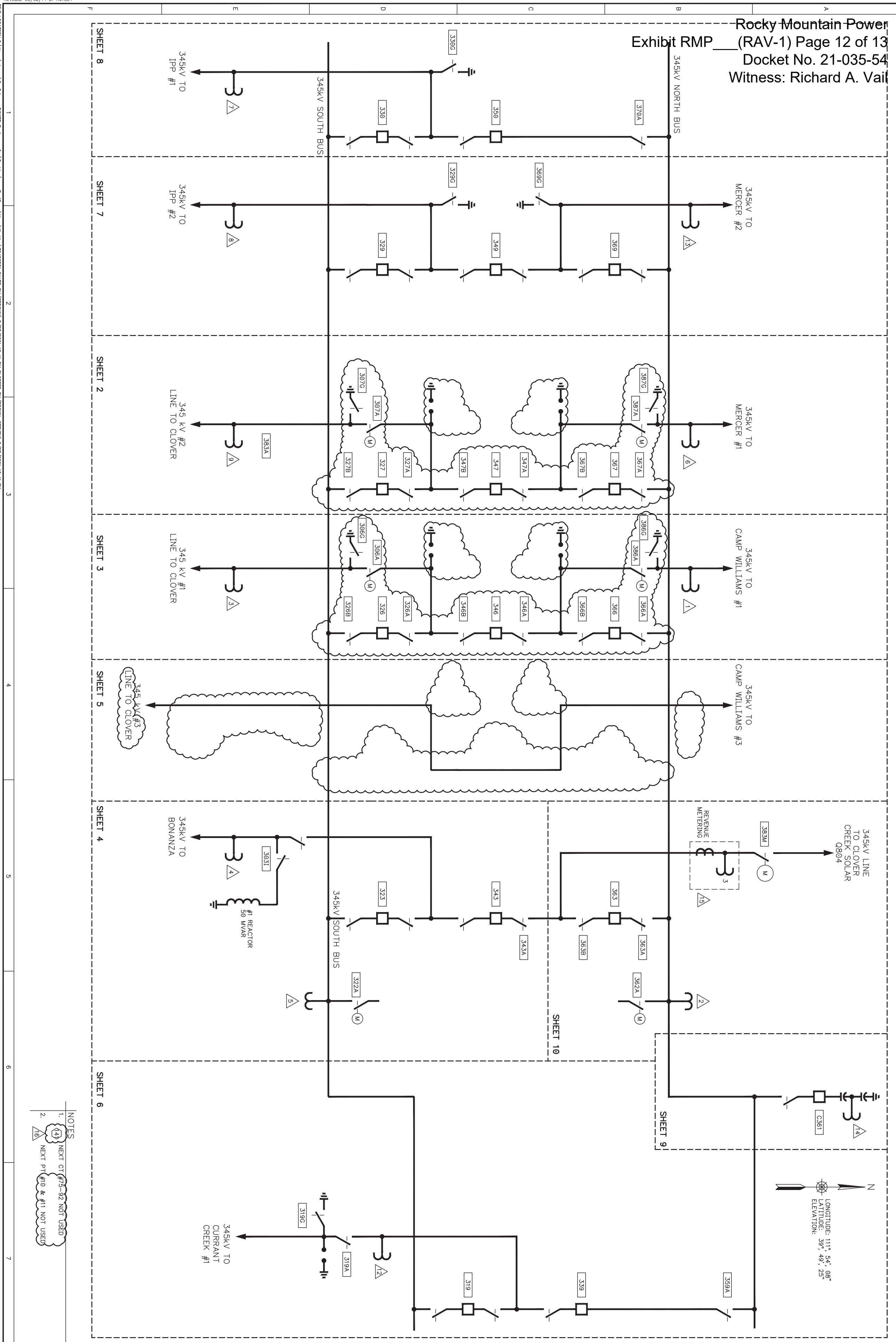


LITTLE SNAKE SUBSTATION MOFFAT COUNTY, COLORADO ONE LINE DIAGRAM KEY SHEET	PROTECTION & CONTROL	PACIFICORP A BERKSHIRE HATHAWAY ENERGY COMPANY	NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
	PROJ/ER# 10044403	DISCIPLINE ENG.	0C	06/04/21	WO# 10044403 ISSUED FOR FSC BID	A. CAHOW/PEI	S. BROWN/PEI	B. PERRY/PEI	
	PL# 083000	PROJECT ENG.							
	ENG. A. CAHOW/PEI — DES. A. CAHOW/PEI	APPROVAL ENG.							
REVISION 0C — 198440.001 — SHEET 1 OF 6	DR. S. BROWN/PEI — CH. B. PERRY/PEI — SCALE: NONE								

REVISED 05/02/14 D. HURLEY

FILE LOCATION:C:\Users\sbrown\OneDrive - POWER Engineers, Inc\Desktop\new PacifiCorp\Mona\Working\70456R01 SAVED BY:(SBROWN) 8/27/2021 12:41 PM PLOTTED BY:(BROWN, STEVEN) 8/27/2021 12:41 PM

Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 12 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



MONA SUBSTATION
JUAB COUNTY, UTAH
ONE LINE DIAGRAM
KEY SHEET

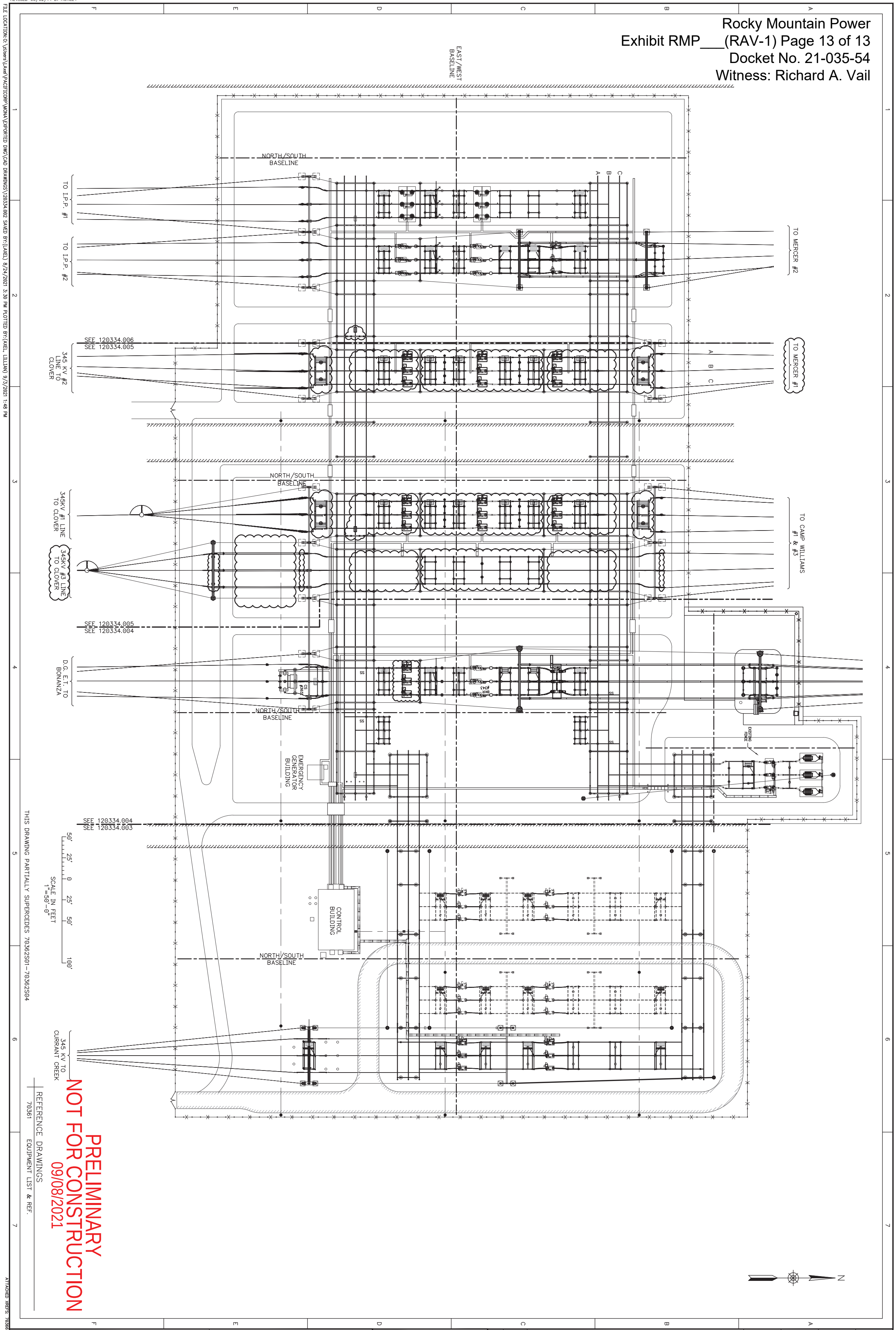
REVISION 22 | 70456R01 | SHEET 1 OF 10

PROTECTION & CONTROL

PROJ/ER#	10005895	DISCIPLINE ENG.	
PL# 086141			
DATE:	08/01/2000	PROJECT ENG.	DENNIS NORMAN, P.E.
ENG. KRR	DES.		
DR. LJM	CH. KRR	APPROVAL ENG.	KEVIN A. FREESTONE
SCALE:	NONE		

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
19	06/03/14	WO# 10050697 ADD SERIES REACTOR, GRAD. CAP., SURGE ARRSTR; RELOC. WAVE TRAP	N. JONES	D. STEVENS	L. PEREZ	G. STRATTON
20	05/07/19	WO# 10066656 RENAME CAMP WILLIAMS #2 LINE TO MERCER #1 AND CAMP WILLIAMS #4 LINE TO MERCER #2	M. PAYNE	E. NGUYEN	M. LUKIC	D. HEFFERNAN
21	08/05/20	WO# 10070273 ADDED CLOVER CREEK SOLAR LINE, BREAKER CB363, SWITCHES 363B, 343A, AND 363M. ADDED SHEET 10	N. ANDERSON/SCI	R. MARTEN/SCI	J. ROBERTUS/SCI	R. JEPSEN/SCI
22	09/01/21	WO# 10073096 REPLACED BKRS 326,346,366,327,347,367. REMOVE BKRS 325,345,365. ADD BACK UP BUS DIFFS	J. LOPEZ/PEI	E. CASTRO/PEI	B. PERRY/PEI	
		ISSUED FOR BID				

Rocky Mountain Power
Exhibit RMP___(RAV-1) Page 13 of 13
Docket No. 21-035-54
Witness: Richard A. Vail



MONA SUBSTATION JUAB COUNTY, UTAH GENERAL PLAN KEY SHEET	ELECTRICAL		PACIFICORP A BERKSHIRE HATHAWAY ENERGY COMPANY
REVISION 8	PROJ/ER# 10030356	DISCIPLINE ENG.	
120334.002	PL# 086141	PROJECT ENG. ERIK K. BROOKHOUSE	
SHEET 2	DATE: 03/27/2006	APPROVAL ENG. HAMID R. SHARIFNIA	
	ENG. E. BROOKHOUSE; DES. D. WOUTERS		
	DR. D.WOLFF; CH. M. MARLEAU		
	SCALE: 1"=50'-0"		

NO.	DATE	REVISIONS	ENGINEER	DES./ DR.	CHECKED	APPROVED
5	08/06/13	WO# 10050323 ADDED WAVE TRAPS ON CAMP WILLIAMS LINE #1, #2 AND #3, PHASE B & C	R. JEPSEN/SCI	M. ANDREASEN/SCI	R. JEPSEN/SCI	M. MUHLENHAUPT/SCI
6	09/10/13	WO# 10050323 REMOVED WAVE TRAPS ON CAMP WILLIAMS LINE #2, PHASE B & C	R. JEPSEN/SCI	M. ANDREASEN/SCI	R. JEPSEN/SCI	M. MUHLENHAUPT/SCI
7	06/03/14	WO# 10050697 ADD SERIES REACTOR TO HUNTINGTON LINE	N. JONES	I. OREST	H. JOHNSON	R. FUERST
8	09/01/21	WO# 10073096 REMOVAL OF BAY 5 EQUIPMENT & UPGRADED BAY 6 & 7 TO 3000 AMP; ISSUED FOR BID	B.CULTON/PEI	L.AXEL/PEI	B.CULTON/PEI	

Rocky Mountain Power
Docket No. 21-035-54
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Rick T. Link

October 2021

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

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning, Procurement and Optimization. I am testifying on behalf of PacifiCorp d/b/a Rocky Mountain Power (the "Company").

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's energy supply management and resource planning and procurement functions, which includes the integrated resource plan ("IRP"), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and for conducting competitive request for proposal ("RFP") processes consistent with applicable state procurement rules and guidelines.

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. Over this time period, I held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, 2019 and 2021 IRPs; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now

ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Utah Public Service Commission ("Commission"), the Wyoming Public Service Commission ("Wyoming Commission"), the Idaho Public Utilities Commission, the Public Utility Commission of Oregon ("Oregon Commission"), the Washington Utilities and Transportation Commission, and the California Public Utilities Commission.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I present and explain the economic analysis that supports PacifiCorp's decision to construct Energy Gateway South (Segment F), a 416-mile, 500-kilovolt ("kV") overhead transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah ("Gateway South"). I summarize PacifiCorp's assessment of Gateway South in the 2021 IRP, which was conducted together with an assessment of Gateway West – Windstar-Aeolus (Segment D.1) ("Gateway West Segment D.1"), (collectively, the "Transmission Projects"). Gateway West Segment D.1 is a 59-mile, 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming and re-construction of an existing, 57-mile, 230-kV transmission line from the Shirley Basin substation to the Dave Johnston substation near Glenrock, Wyoming ("Gateway West Segment D.1"), (collectively, the "Transmission Projects"). My testimony also summarizes PacifiCorp's 2020 all-source request for proposal ("2020AS RFP") to solicit new resources including those enabled by the Transmission Projects and provides economic analysis demonstrating the customer benefits associated with construction of the Transmission Projects.

Q. Why does your testimony address the Transmission Projects, when the Company is requesting a CPCN for Gateway South?

A. Gateway South and Gateway West Segment D.1 were analyzed together, both in the 2021 IRP and in this case, because each line is required to interconnect new generating resources in eastern Wyoming, as described in more detail in the direct testimony of Company witness Mr. Rick A. Vail. Because the economic benefits of Gateway South include the ability to interconnect new, low-cost resources, and those low-cost resources require both Gateway South and Gateway West Segment D.1 to interconnect, the Company appropriately included the costs of both Transmission Projects in its economic analysis. The requested Certificate of Public Convenience and Necessity ("CPCN"), however, applies to only Gateway South because Gateway West Segment D.1 is located entirely in Wyoming.

Q. Please summarize your direct testimony regarding the Transmission Projects.

A. The 2021 IRP confirmed that the Transmission Projects remain a key transmission investment that will enable the procurement of low-cost wind facilities to reliably meet the Company's need for additional resources to serve customers and are expected to produce significant customer benefits. Critically, as discussed in detail by Mr. Vail, the

Transmission Projects will enable PacifiCorp to meet its Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT") obligations in 13 executed interconnection service and transmission service contracts, including a transmission service agreement to provide 500 megawatts ("MW") of firm point-to-point ("PTP") transmission service that requires Gateway South.

When applying the most conservative assumptions for unavoidable transmission costs—a new 230-kV line to meet the Company's OATT requirements for the firm PTP transmission service contract—customer benefits range from $128 to $260 million when compared to resource portfolios without the Transmission Projects using medium natural gas and medium carbon dioxide ("CO_2") assumptions. When assuming the cost of the Transmission Projects are unavoidable to meet the Company's OATT requirements for all 13 interconnection service and transmission service contracts, customer benefits range from $610 million to $742 million under medium natural gas and medium CO_2 price inputs. The Transmission Projects are scheduled to be in operation by the end of 2024, which ensures that potential new wind resources selected in the 2020AS RFP that are dependent upon the Transmission Projects can come online in time to qualify for the 60 percent federal production tax credit ("PTC").

PacifiCorp has identified the final shortlist of bids selected in the 2020AS RFP. Those shortlist bids include over 1,600 MW of new wind resources that require the Transmission Projects to interconnect to PacifiCorp's transmission system. PacifiCorp has analyzed the economic benefits of the Transmission Projects together with the wind resources that are enabled by the Transmission Projects using the modeling and assumptions from the 2021 IRP, which was completed and filed on September 1, 2021.

PacifiCorp requests that the Commission grant a CPCN no later than June 1, 2022, so that construction can begin no later than June 2, 2022.

Q. Please summarize your economic analysis of the Transmission Projects.

A. PacifiCorp's economic analysis demonstrates that the Transmission Projects are necessary and will serve the public interest. As explained by Mr. Vail, PacifiCorp's transmission system in eastern Wyoming must be upgraded to meet multiple interconnection service and transmission service agreements. The Transmission Projects address this need, while producing significant customer benefits by enabling new wind resources capable of producing PTCs for 10 years. By qualifying for these federal tax credits, the cost of these new wind resources, which already have no fuel costs or emissions, are greatly reduced relative to other resource options that would otherwise be needed to meet the Company's projected transmission and generation resource needs. These wind resources will also generate renewable-energy credits ("RECs"), which can be sold in the market to create additional revenues that would offset costs.

PacifiCorp's economic analysis here uses consistent modeling inputs as those used in the 2021 IRP, including the expected net costs associated with the bids selected in the 2020AS RFP that require the Transmission Projects. The analysis reviewed the change in revenue requirement due to the Transmission Projects, and associated resources that are dependent upon the Transmission Projects, using the Company's IRP modeling tool across five different scenarios that pair varying natural gas price assumptions with varying CO_2 policy assumptions ("price-policy scenarios"). The price-policy scenarios include:

- Medium natural gas prices paired with medium CO_2 prices, which I refer to as the "MM" price-policy scenario;
- Medium natural gas prices without a CO_2 price, which I refer to as the "MN" price-policy scenario;
- High natural gas prices paired with high CO_2 prices, which I refer to as the "HH" price-policy scenario;
- Low natural gas prices without a CO_2 price, which I refer to as the "LN" price-policy scenario; and
- The Social Cost of Greenhouse Gas, which I refer to as the "SCGHG" price-policy scenario.

For each of these price-policy scenarios, PacifiCorp calculated the change in system revenue requirement between cases with and without the Transmission Projects and the associated wind resources through 2040, where capital revenue requirement is levelized.

The results of my economic analysis confirm that the Transmission Projects are expected to generate customer benefits. Under the MM price-policy scenario, the present-value revenue requirement differential ("PVRR(d)") customer benefit when using the most conservative assumptions for unavoidable transmission is *$128 million* and the risk-adjusted PVRR(d) benefits are *$260 million*. When assuming the cost of the Transmission Projects are unavoidable, the PVRR(d) under the MM price-policy scenario yields a *$610 million* customer benefit and a risk-adjusted benefit of *$742 million*. These benefits conservatively do not assign any value to the RECs that will be generated by new resources made available due to the Transmission Projects.

The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

I also calculated the change in annual nominal revenue requirement through 2040 to provide a sense of potential rate pressures relative to a case that does not include the Transmission Projects.

2021 INTEGRATED RESOURCE PLAN

Q. Does the 2021 IRP identify a need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of the 2021 IRP is to forecast the need for resources and then evaluate different ways to meet that need over time. In the 2021 IRP, the assessment of resource need is presented in Volume I, Chapter 6. The load-and-resource balance shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and then rising over time to over to 6,600 MW by 2040.[1] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,627 MW. Consistent with prior IRPs, in the 2021 IRP all resource portfolios produced that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, and market resources necessary to fill this need.

Q. How does the preferred portfolio identified in the 2021 IRP respond to the identified resource need?

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost

[1] *See* 2021 IRP, Vol. I, Table 6.12.

and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflects a cost-conscious plan that includes near-term investments in renewable resources that can capture tax credits before they expire or decrease and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Are the Transmission Projects a part of the 2021 IRP preferred portfolio?

A. Yes. As described in Volume I, Chapter 4 of the 2021 IRP, the preferred portfolio includes both Gateway South and Gateway West Segment D.1. In the 2021 IRP, the Transmission Projects are assumed to be placed in service by the end of 2024, consistent with current construction timelines discussed by Mr. Vail. The Transmission Projects will enable the addition of new wind facilities that contribute to meeting 1,627 MW of projected resource need beginning 2025.

Q. Was the modeling used in the 2021 IRP able to endogenously select transmission resources?

A. Yes. For the first time in the 2019 IRP, the Company configured the System Optimizer ("SO") model so that it could select certain transmission investments necessary to enable new resource selections as part of its objective to minimize total system costs. The Company upgraded to the more advanced Plexos model for the 2021 IRP (discussed in more detail below), which also has the ability to endogenously view costs and transmission capability associated with certain transmission upgrades and allows for selection of specific transmission investments that coincide with new resource additions. Endogenous transmission modeling capabilities in the Plexos model include the consideration of 1) new incremental transmission options tied to resource selections; 2) existing transmission rights tied to the use of post-retirement brownfield sites; 3) costs associated with these transmission options; and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. When the 2021 IRP modeling evaluated transmission investments, it accounted for the assumed cost for those investments and the value generated by those investments by enabling low-cost resource options and better optimizing how resources are used to serve load or lower system costs.

Q. Were the Transmission Projects included as an element of the least-cost portfolios evaluated during the 2021 IRP portfolio-development process?

A. Yes. The Transmission Projects, and the associated 2020AS RFP bids dependent on the Transmission Projects for interconnection, were included as a least-cost element of all portfolios except those explicitly designed to eliminate them for the purpose of calculating a PVRR(d).

Q. What new transfer capability and interconnection capacity do the Transmission Projects add to PacifiCorp's system?

A. Completion of the Transmission Projects will increase the transfer capability between the Aeolus substation in eastern Wyoming and the Clover substation located near Mona, Utah by 1,700 MW and enable the interconnection of 2,030 MW of new resources in eastern Wyoming.

Q. Please describe key factors supporting the inclusion of the Transmission Projects in PacifiCorp's 2021 IRP preferred portfolio.

A. The Transmission Projects allow PacifiCorp to implement system improvements, support the full capacity rating of Gateway South and West, and enable the addition of incremental Wyoming renewable resources to support customer needs and deliver value for customers in the most cost-effective way. As noted earlier, the Transmission Projects will come online by the end of 2024, and that timing allows the Company to meet its projected resource need beginning 2025 with low-cost resources that can qualify for federal tax credits before they are reduced or phased out. This timing also enables PacifiCorp to cost-effectively meet its obligation to provide nearly 2,500 MW of interconnection and transmission service requests, including 500 MW of firm PTP transmission service to a third-party customer, as described by Mr. Vail. Gateway South will increase transfer capability between the Aeolus substation in eastern Wyoming and the Clover substation near Mona, Utah, which will help PacifiCorp better optimize its resources used to serve system load.

Q. Please describe the reliability benefits of the Transmission Projects identified in the 2021 IRP.

A. Chapter 5 of the 2021 IRP addresses reliability and resiliency, including a discussion of the Transmission Projects' contributions to a reliable and resilient system to serve customers. Gateway South directly connects eastern Wyoming to central Utah while enhancing reliability throughout PacifiCorp-served regions. Connecting into the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or Utah to serve customer load.

Moreover, by allowing additional generation resources to interconnect and serve load, the Transmission Projects will lessen PacifiCorp's reliance on volatile and potentially diminishing market transactions to serve load. Given concerns over regional resource adequacy, reducing reliance on the market better ensures a stable and reliable supply of capacity and energy going forward.

In addition, Gateway South improves reliability by relieving the stress on the transmission system in eastern Wyoming and central Utah. For example, the 2021 IRP explains that the addition of the Gateway South line in Wyoming relieves stress on the underlying 230-kV transmission system while improving the reliability in that region. Similarly, the addition of the Gateway South line in central Utah unloads the underlying 345-kV transmission system improving reliability in that region. Essentially, the 500-kV line brings two distant areas closer to each other in a way that improves regional reliability.

The 2021 IRP also addresses the reliability benefits resulting from the construction of Gateway West Segment D.1. In particular, the IRP explains that Gateway West Segment D.1 provides a new transmission path allowing for resource development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Construction of Gateway West Segment D.1 is also a prerequisite for interconnecting new resources, including those selected in the 2020AS RFP, which I discuss in more detail below.

Mr. Vail's testimony addresses transmission system reliability and interconnection issues in greater detail.

Q. Did PacifiCorp include action items for the Transmission Projects in its 2021 IRP action plan?

A. Yes. The 2021 IRP action plan, which lists the specific steps PacifiCorp will take over the next two to four years to deliver resources in the preferred portfolio, includes the following action items associated with the Transmission Projects:

Gateway South:

- By the second quarter of 2022, obtain CPCNs from this Commission and the Wyoming Commission;
- By the end of the first quarter of 2022, obtain Bureau of Land Management notice to proceed to construct Gateway South.
- In the third quarter of 2024, construction of Gateway South is expected to be completed and placed in service.

Gateway West Segment D.1:

- By the second quarter 2022, obtain CPCN from the Wyoming Commission;
- By the third quarter of 2022 complete rights-of-way easement acquisition;
- In the third quarter of 2024, construction of Gateway West Segment D.1 to be completed and placed in service.

Q. Was Gateway South also included in the preferred portfolio selected in the 2019 IRP?

A. Yes. Like the 2021 IRP, the 2019 IRP preferred portfolio also included Gateway South.

Q. Did the Commission acknowledge the 2019 IRP?

A. The Commission acknowledged the 2019 IRP generally, but declined to specifically acknowledge the Action Plan, which included construction of Gateway South.[2] The

[2] *PacifiCorp's 2019 Integrated Resource Plan*, Docket No. 19-035-02, Order (May 13, 2020) (hereinafter "2019 IRP Order").

Commission made clear, however, that, "Declining to acknowledge or approve the Action Plan does not constitute denial of any specific resource."[3] Instead, whether the Commission's order "has any impact on resource approval dockets or other proceedings will be evaluated in those separate dockets."[4]

Q. Did the Commission provide any specific guidance regarding the evaluation of Gateway South?

A. Yes. First, the Commission was concerned that PacifiCorp "did not model the Preferred Portfolio without the yet-to-be-built Gateway South as a presumed component," which was "inadequate" because the 2019 IRP Action Plan called for "nearly immediate construction of the line without identifying and justifying selection of the specific resources that will rely on it and, in particular, their geographic location."[5]

Second, the Commission was concerned that PacifiCorp did not model a "potential alternative transmission expansion case evaluated by [Northern Tier Transmission Group ("NTTG")] in its 2018-2019 Regional Transmission Plan that demonstrated sufficient merit to warrant PacifiCorp's further study."[6]

Q. Has the Company addressed the Commission's concerns in the 2021 IRP and in this filing?

A. Yes. First, the Company's economic analysis, which is the same analysis included in the 2021 IRP, explicitly modeled the preferred portfolio with and without the Transmission Projects and the resources that rely on Transmission Projects. Moreover, the modeling with and without the Transmission Projects used the actual wind

[3] *Id.* at 26.
[4] *Id.*
[5] *Id.* at 22.
[6] *Id.* at 22.

resources selected in the 2020AS RFP, which addressed the Commission's concern that the 2019 IRP did not identify the specific resources that would rely on Gateway South. The results of this analysis demonstrated substantial customer benefits from constructing Gateway South and interconnecting over 1,600 MW of new PTC-eligible wind resources.

Second, in this filing, the Company included a specific sensitivity that modeled the NTTG alternative discussed by the Commission, as discussed in more detail below. The results of this analysis favored construction of Gateway South by a significant margin. Mr. Vail's testimony provides additional analysis demonstrating that the NTTG case is not a reasonable alternative to Gateway South.

2020 ALL SOURCE REQUEST FOR PROPOSALS

Q. Please provide an overview of the 2020AS RFP.

A. The 2020AS RFP is an all-source RFP seeking resources to meet the Company's projected resource needs that were identified in the 2019 IRP. Based on the cost-and-performance assumptions for proxy resources in the 2019 IRP, the Company expected that new wind, solar and battery energy storage systems ("BESS") were likely to be the most cost-competitive types of resources offered into the 2020AS RFP. However, bidders could offer proposals for other types of resources (*i.e.*, natural gas, pumped storage, *etc.*).

The Commission approved the 2020AS RFP on July 2, 2020, in Docket No. 20-035-05. The Company also received approval of the 2020AS RFP from the Oregon

Commission in Docket No. UM 2059[7] and the 2020AS RFP was then released to market.

Q. Although the 2019 IRP contemplated that the new resources would reach commercial operation by the end of 2023, did the 2020AS RFP require that resources offering bids reach commercial operation by the end of 2023?

A. No. When the 2019 IRP was filed, PacifiCorp assumed new wind resources would need to achieve commercial operation by the end of 2023 to be eligible for a 40 percent PTC. Similarly, PacifiCorp assumed that solar resources or solar collocated with BESSs would need to achieve commercial operation by the end of 2023 to qualify for the 30 percent investment tax credit ("ITC"). After the 2019 IRP was filed, federal legislation was passed that extended the PTC to allow wind projects to come online as late as 2024 and qualify for a 60 percent PTC. While the timing for the phased reduction of the ITC has not changed since the 2019 IRP was filed, in response to the new legislation that extends and increases the value of the PTC, PacifiCorp accepted bids into the 2020AS RFP that can achieve commercial operation by the end of 2024.

Q. What was the market response to the 2020AS RFP?

A. The 2020AS RFP elicited a robust market response that produced over 28,000 MW of conforming bids with an additional 12,500 MW of bids that did not conform with minimum requirements set forth in the 2020AS RFP. Bids for 24 projects totaling over 9,000 MW of resource capacity located in eastern Wyoming were submitted.

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[7] The Oregon Commission has established competitive bidding requirements for certain resource acquisitions by Oregon's investor-owned utilities. *See In the Matter of the Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324, Appendix A (Aug. 30, 2018).

Q. What were the proposed commercial operation dates for the eastern Wyoming bids that rely on the Transmission Projects for interconnection?

A. The bids that rely on the Transmission Projects for interconnection all proposed 2024 commercial operation dates, which enabled PacifiCorp to defer construction of the Transmission Projects an additional year relative to the timing assumed in the 2019 IRP.

Q. How did the Company evaluate the bids that were submitted?

A. The first step in the process was identification of the initial shortlist, which was made public on October 29, 2020. The initial shortlist included 5,453 MW of renewable resource capacity: 2,974 MW of solar or solar with storage (1,130 MW of battery storage), 2,479 MW of wind, and 200 MW of standalone BESS. PacifiCorp then initiated the capacity factor evaluation process (performed by third-party expert WSP Global). The initial shortlist contained a mix of various ownership structures, including proposals for power-purchase agreements ("PPAs"), build-transfer agreements ("BTAs"), and battery storage agreements ("BSAs").

Q. Please describe how PacifiCorp selected the final shortlist.

A. Consistent with the bid evaluation and selection process outlined in the 2020AS RFP, the final shortlist selection process was implemented in two basic phases using the IRP modeling tools: the portfolio-development phase and the scenario-risk phase. At the time it conducted this analysis, the Company was still relying on the SO model and Planning and Risk ("PaR") used in the 2019 and previous RFPs and IRPs.

Q. Please describe the analysis conducted in the portfolio-development phase.

A. The portfolio-development phase identified the least-cost combination of bids using a methodology consistent with the approach used to produce resource portfolios in PacifiCorp's 2019 IRP.

First, the best-and-final pricing for each bid was processed and incorporated into the SO model and PaR as modeling inputs.

Second, the SO model was used to develop bid portfolios, reflecting corrected model inputs, containing the least-cost combination of bids over a 20-year planning horizon (2019 through 2038). The SO model optimized its resource portfolio selections from all the bids included in the initial shortlist, as well as from all other proxy-resource alternatives used to develop resource portfolios in PacifiCorp's 2019 IRP (e.g., front-office transactions or "FOTs," RFP demand-side management resources, etc.). PacifiCorp did not force the SO model to select any bid or any combination of bids. PacifiCorp initially developed bid portfolios for three price-policy scenarios, which reflect different pairings among three natural-gas price forecasts and three CO_2 price forecasts (i.e., an LN, MM, and HH bid portfolio). Three additional resource portfolios, one for each price-policy scenario, that did not allow any bid selections were used to calculate a PVRR(d) between two system simulations—one that included the 2020AS RFP bids and the Transmission Projects, and one without.

Q. Please describe the scenario-risk phase.

A. The scenario-risk phase of the bid-evaluation process was implemented by evaluating the different resource portfolios (those produced when LN, MM, and HH price-policy assumptions were applied) under each of the three price-policy scenarios. This step provides insight as to how each of the three bid portfolios perform under a range of conditions. The Company also performed sensitivities to test bid selections and system costs under alternative market price assumptions, market sale assumptions, and federal tax incentive assumptions.

Q. Did the Company also perform additional RFP modeling related specifically to Gateway South?

A. Yes. During the Utah RFP-approval process, parties expressed concern that the RFP "did not fully and effectively consider transmission scenarios that did not include the unbuilt Gateway South. . . transmission line."[8] To address this concern, parties recommended that the Company's modeling include scenarios without Gateway South. The Commission "found these concerns compelling as it did not appear the transmission costs associated with scenarios that did not entail construction of Gateway South would be accurately and fairly compared with those that assumed and relied on its construction."[9] In response to these concerns, the Company agreed to the following, which the Commission concluded "are reasonable and adequately address the issues":

> 1) Inasmuch as the final shortlist evaluation includes bids dependent upon Gateway South, the Company will perform, at minimum, a sensitivity that removes Gateway South and all bids that require Gateway South; and
>
> 2) Inasmuch as the final shortlist evaluation includes bids dependent upon Gateway South, the Company will perform a sensitivity that replaces Gateway South with an alternative transmission build-out scenario that is reasonably aligned with options identified in the NTTG's 2018-2019 Regional Transmission Plan.[10]

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[8] *Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals*, Docket No. 20-035-05, Order Approving 2020 All Source RFP at 14 (July 17, 2020).
[9] Order Approving 2020 All Source RFP at 14.
[10] Order Approving 2020 All Source RFP at 15.

Q. Did the Company provide modeling required by the Commission when approving the 2020AS RFP?

A. Yes. As discussed above, the Company performed the with and without Gateway South study as part of the portfolio-development phase of the 2020AS RFP. The Company also performed that same analysis in this case (discussed below). The Company also modeled the NTTG alternative (discussed below).

Q. What resources were identified for inclusion on the final shortlist based on the bid evaluation and selection process outlined above?

A. After evaluating a range of potential bid portfolios, and after accounting for bid updates resulting from interconnection study results, the Company selected the final shortlist, which includes:[11]

- 1,792 MW of new wind capacity
    - 590 MW as BTAs
    - 1,202 MW as PPAs
- 1,302 MW of solar capacity as PPAs
- 697 MW of BESS
    - 497 MW of BESS capacity is paired with solar bids
    - 200 MW is standalone BESS capacity as a BSA

[11] The final shortlist originally included an additional solar bid collocated with BESS. Shortly after the bidder was notified its project was on the final shortlist, it withdrew the bid from the 2020AS RFP. As summarized, this bid is not included in the total capacity shown.

Q. Which resources selected to the final shortlist are dependent on the Transmission Projects for interconnection?

A. Six final shortlist bids, representing over 1,600 MW of wind generation, require the Transmission Projects to interconnect to PacifiCorp's transmission system. Table 1 summarizes the wind bids that require the Transmission Projects to achieve interconnection.

Table 1.
2020AS RFP Wind Bids that Require the Transmission Projects to Achieve Interconnection

Project	Bidder	Structure	Capacity (MW)
Cedar Springs IV	NextEra	PPA	350
Boswell Springs	Innergex	PPA	320
Two Rivers	BlueEarth Renewables LLC and Clearway Renew LLC	PPA	280
Anticline	NextEra	PPA	101
Rock Creek I	Invenergy	BTA	190
Rock Creek II	Invenergy	BTA	400

Q. Did PacifiCorp conduct the 2020AS RFP under the oversight of independent evaluators?

A. Yes. PacifiCorp conducted the solicitation process in accordance with the approvals received from the Commission and the Oregon Commission and with the comprehensive oversight of two independent evaluators—one retained by the Commission (Merrimack Energy Group) and one retained by PacifiCorp and appointed by the Oregon Commission (PA Consulting Group, Inc.).

Q. What were the independent evaluators' conclusions regarding the 2020AS RFP?

A. Both independent evaluators concluded that the process was fair and transparent and the bids selected to the final shortlist were reasonable.

Q. Please describe the Utah independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Shortlist Report,[12] the Utah independent evaluator concluded that the RFP was fair, reasonable, and in the public interest. In particular, the Utah independent evaluator concluded:

- The market response to the RFP was robust and, "Based on the unbelievable response from the market it is safe to say that the solicitation process resulted in a very competitive process with many more proposals generally submitted than the expected requirements by bubble identified by PacifiCorp."[13]
- PacifiCorp engaged the bidders throughout the process in a timely manner to ensure that all bidders were treated fairly.
- All bidders were treated the same, had access to the same information at the same time, and had an equal opportunity to compete.
- PacifiCorp implemented its evaluation and selection process consistent with its proposed evaluation and selection process as outlined in the RFP in a structured and consistent manner designed to result in the selection of a portfolio of projects that would result in a least cost solution.
- PacifiCorp subjected all bidders to the same information requirements and conducted a consistent evaluation process with all proposals treated equally in terms of the evaluation methodology and information required of each bidder.
- The selection process was unbiased with respect to ownership structures, i.e., the process did not unreasonably favor bids that resulted in a utility-owned resource.

Q. Please describe the Oregon independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Closing Report,[14] the Oregon independent evaluator concluded that the final shortlist reflected a diverse portfolio of competitive resources that achieves the resource

[12] The Shortlist Report (hereinafter, the "Utah IE Shortlist Report") was filed with the Commission in Docket No. 20-35-05 on September 2, 2021, and is available here: https://psc.utah.gov/2020/01/24/docket-no-20-035-05/.
[13] Utah IE Shortlist Report at 74.
[14] The Closing Report was filed by PacifiCorp in Oregon Commission docket UM 2059 on June 15, 2021, and is available here: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22320.

adequacy and least cost goals set forth in PacifiCorp's IRP, based on the following conclusions:

- PacifiCorp's procurement process, scoring methodology and results were fair and free of bias across all bids and bidders.
- PacifiCorp applied the rules of the 2020AS RFP in an unbiased manner, communicated transparently with the independent evaluators regarding their modelling processes and with stakeholders regarding their decisions.
- PacifiCorp's bid price scores were on average consistent with the independent evaluator's independent scoring methodology.
- PacifiCorp's utilization of an outside consultant, WSP Global, to evaluate wind, solar, and battery storage benefitted stakeholders.
- The final shortlist was reasonably aligned with the 2019 IRP preferred portfolio.

MODELING ASSUMPTIONS

Q. Were the assumptions used in your economic analysis in this filing consistent with the assumptions used to develop the 2021 IRP?

A. Yes. The assumptions used in the economic analysis discussed below are the same assumptions that were used to develop the 2021 IRP.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis.

A. The economic analysis of the Transmission Projects includes five price-policy scenarios—the MM, MN, HH, LN, and SCGHG price-policy scenarios. These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net-power costs ("NPC") benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Transmission Projects. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 2 summarizes the price-policy scenarios used to analyze the Transmission Projects.

Table 2. Price-Policy Scenario Assumption Overview

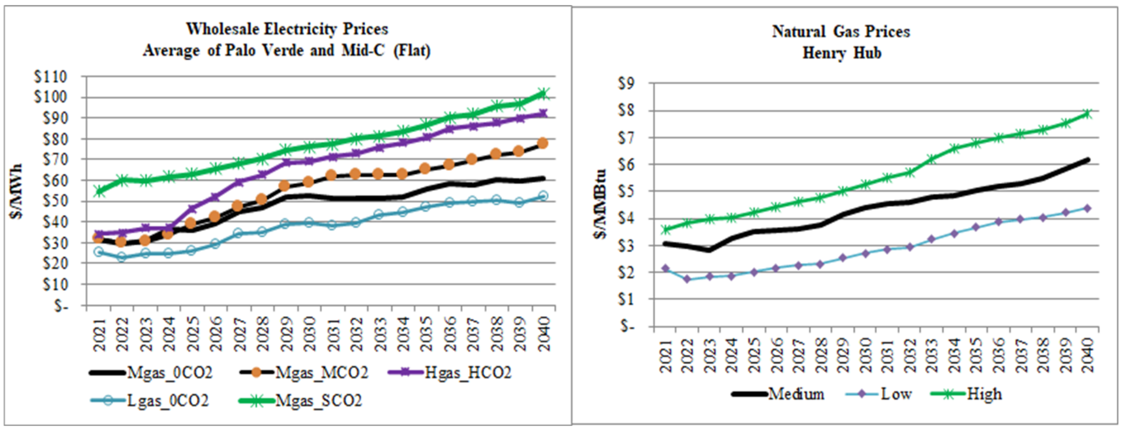
Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)	CO_2 Price Description
MM	$4.44	$9.93/ton starting 2025 rising to $57.94/ton in 2040
MN	$4.44	None
HH	$5.64	$22.57/ton starting 2025 rising to $102.48/ton in 2040
LN	$2.94	None
SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve ("OFPC") dated March 31, 2021, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2021 IRP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (March 31, 2021, in this case). As such, these 36 months are market forwards as of March 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party, multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by

AURORAXMP4 ("Aurora"), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios.

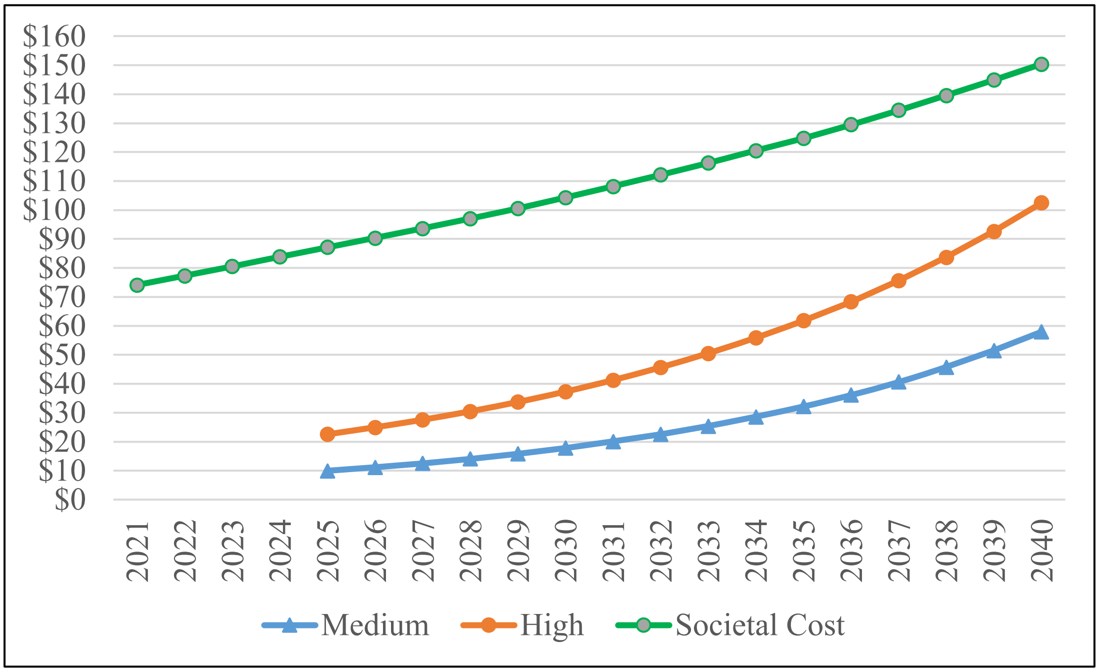
Figure 1. Natural Gas Price Assumptions



Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party, multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp also incorporated the social cost of greenhouse gas, which is assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the social cost of greenhouse gas is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Figure 2 shows the three non-zero CO_2 price assumptions used to analyze the Transmission Projects.

Figure 2. CO_2 Price Assumptions



Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of its analysis of the Transmission Projects?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client "off-the-shelf" subscription services.

MODELING METHODOLOGY

Q. Please describe the modeling methodology that PacifiCorp used in its analysis of the Transmission Projects.

A. PacifiCorp calculated a system PVRR by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP. Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Transmission Projects, and the other simulation excludes them. In addition, because wind bids selected to the 2020AS RFP final shortlist that are located in eastern Wyoming cannot interconnect without the Transmission Projects, these wind resources are also eliminated from the simulation without the Transmission Projects. When the two simulations are compared, changes to system costs are attributable to the Transmission Projects. The simulation with the Transmission Projects can add wind bids located in eastern Wyoming that are on the 2020AS RFP final shortlist. Beyond 2024, proxy resource options from the 2021 IRP are available to meet system needs.

Customers are expected to realize benefits when the system PVRR from the simulation with the Transmission Projects is lower than the system PVRR without the Transmission Projects. Conversely, customers would experience increased costs if the system PVRR with the Transmission Projects were higher than the system PVRR without the Transmission Projects.

Q. Are there any other costs that differ between the simulations with and without the Transmission Projects?

A. Yes. The simulation that excludes the Transmission Projects includes the cost of transmission upgrades necessary to accommodate PacifiCorp's obligation to provide 500 MW of firm PTP transmission service to a third-party customer. As explained in more detail by Mr. Vail, these transmission upgrade costs were included because, even conservatively ignoring all the executed interconnection service and transmission service contracts listing the Transmission Projects as prerequisites and focusing solely on the upgrades required to provide service under one transmission service contract, PacifiCorp assumed it would need to construct a 230-kV line by the end of 2024 at an estimated cost of approximately $1.4 billion.

Further, this $1.4 billion cost is the minimum cost for the alternative considering that it includes only the upgrades required to provide service under a single transmission service contract. Additional costs would be incurred to provide service under all interconnection service contracts listing the Transmission Projects as prerequisites. To provide service under all these contracts, it is likely the alternative would be to construct the Transmission Projects, which means that construction of these transmission investments are unavoidable given PacifiCorp's federal open access transmission tariff obligations to grant interconnection and transmission service requests.

Q. Has PacifiCorp upgraded the modeling tools used to evaluate the Transmission Projects?

A. Yes. While the methodology has remained the same, as noted above, in the 2021 IRP PacifiCorp used the more advanced Plexos modeling system, rather than the SO model and PaR that were used in prior IRPs.

Q. Please describe the Plexos model.

A. The Plexos modeling system provides three platforms of the Plexos tool (referred to as Long-term ("LT"), Medium-term ("MT") and Short-term ("ST")), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The Plexos tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years. Portfolios from the LT model are informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk among five price-policy scenarios (MM, MN, HH, LN, and SCGHG). A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used to ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three Plexos models work together to inform the economic analysis presented here?

A. In the first step, resource portfolios (with and without the Transmission Projects and associated wind resources) were developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management ("DSM") alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour; and 2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the Plexos model appropriate for analyzing the customer benefits of the Transmission Projects?

A. Yes. The Plexos model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. Like the prior SO model, the LT model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource and transmission capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Transmission Projects. The ST and MT models, like PaR, provide additional granularity on how the Transmission Projects are projected to affect system operations while assessing stochastic risks. Together, the LT, MT, and ST models are best suited to perform a benefit analysis for the Transmission Projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the Plexos model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. What portfolios did you analyze using the Plexos model in this case?

A. While the description provided above describes generally how the 2021 IRP portfolios were developed, analyzed, and selected, for purposes of this case the two portfolios analyzed are portfolios with and without the Transmission Projects and, as noted above, the without case also removes the wind resources selected in the 2020AS RFP that require the Transmission Projects.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the Transmission Projects?

A. Yes. PacifiCorp analyzed the Transmission Projects under five price-policy scenarios. The economic analysis also includes sensitivities that quantify how changes in new resource capital costs for the two BTA wind projects and capital cost assumptions for the Transmission Projects influence projected customer benefits.

Q. Mr. Vail's testimony indicates that the Transmission Projects will enable up to 2,030 MW of new resources to interconnect in eastern Wyoming. Why does your analysis only account for 1,640 MW?

A. As discussed earlier in my testimony, the economic analysis reasonably accounted for only those wind resources that were selected to the 2020AS RFP final shortlist.

Q. Please summarize the key cost-and-performance assumptions for the Transmission Projects and the new wind resources dependent upon the transmission projects that are included in your economic analysis.

A. Cost-and-performance assumptions for the Transmission Projects and the 1,640 MW of new wind resources are summarized in Confidential Exhibit RMP___(RTL-1).

Q. Does PacifiCorp assume that all the up-front capital costs of the Transmission Projects will be paid by its retail customers?

A. No. The cost of the Transmission Projects is net of revenue credit from other transmission customers. PacifiCorp assumed retail customers would pay 80 percent of the revenue requirement from the up-front capital cost for the Transmission Projects after accounting for an assumed 20 percent revenue credit from other transmission customers.

PRICE-POLICY SCENARIO RESULTS

Q. Please summarize the PVRR(d) results calculated from the Plexos model.

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario. The data that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-2).

Table 3. PVRR(d) (Benefit)/Cost of the Transmission Projects ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($128)	($260)
LN	$755	$670
MN	$393	$289
HH	($932)	($1,100)
SCGHG	($2,568)	($2,819)

As shown above, system costs increase when the Transmission Projects are removed from the portfolio in the MM, HH, and SCGHG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. Without the Transmission Projects, emissions from PacifiCorp's generation resources increase considerably—ranging from 8.4 percent in the MN price-policy scenario to 17.8 percent in the SCGHG price-policy scenario. The LN and MN scenarios unrealistically fail to account for the risk that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions over the planning period. It is also unlikely that gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building the Transmission Projects should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under the HH and SCGHG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios.

Considering that the removal of the Transmission Projects increases system costs among the MM, HH, and SCGHG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk (discussed further below), this analysis supports the necessity of the Transmission Projects and indicates that they are likely to result in robust customer benefits.

Q. Earlier in your testimony, you stated the cost for the 230-kV alternative that is assumed to provide service under a single transmission service contract was a conservative cost floor, and that the Transmission Projects are the likely alternative to providing service under all interconnection contracts listing the Transmission Projects as prerequisites. Did you calculate how the PVRR(d) results presented above would change if you assumed the Transmission Projects would be required to provide service under all these interconnection and transmission service contracts?

A. Yes. This would increase the cost of the "alternative" to equal the cost of the Transmission Projects, which represents a $971 million increase in unavoidable capital relative to what is shown in the table above. This translates into $482 million on a PVRR basis. Table 4 shows the PVRR(d) results with this level of unavoidable capital. When this higher cost is applied to the results, the MN price-policy scenario now shows there are significant customer benefits from the Transmission Projects.

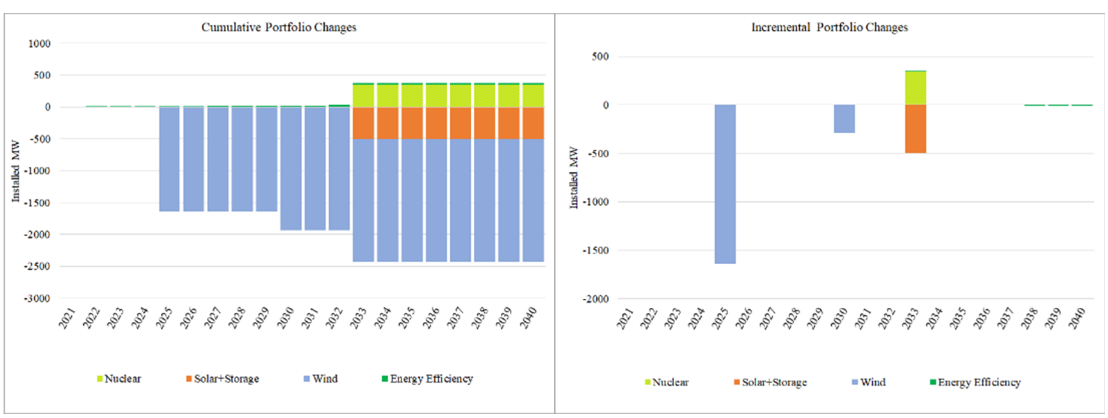
Table 4. PVRR(d) (Benefit)/Cost of the Transmission Projects Assuming the Transmission Projects are Unavoidable ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($610)	($742)
LN	$273	$188
MN	($90)	($194)
HH	($1,414)	($1,582)
SCGHG	($3,050)	($3,301)

Q. Please describe the impact of removing the Transmission Projects and associated wind resources from the 2021 IRP's preferred portfolio.

A. Figure 3 shows the cumulative (at left) and incremental (at right) portfolio changes when the Transmission Projects are eliminated under the MM price-policy scenario. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the Transmission Projects are eliminated. Without the Transmission Projects, the 1,640 MW of wind resources selected in the 2020AS RFP are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an advanced nuclear plant that displaces solar co-located with storage resources.

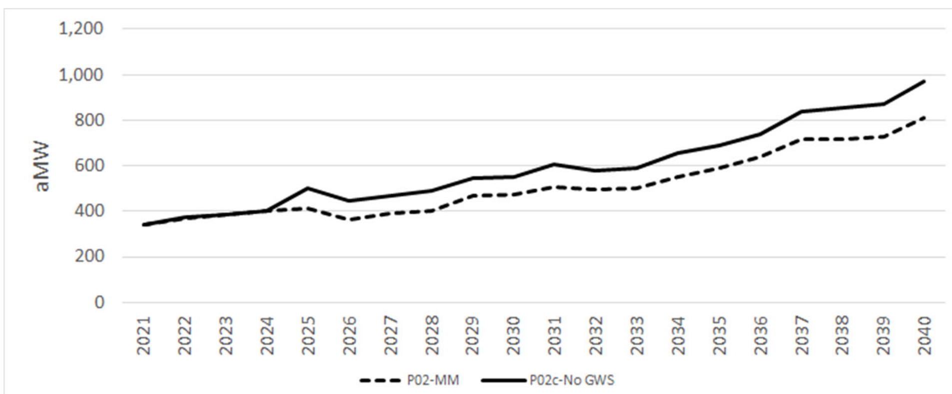
Figure 3. Changes in the Resource Portfolio without the Transmission Projects



Q. Does the removal of the Transmission Projects and associated wind resources increase the Company's reliance on market purchases?

A. Yes. Figure 4 shows how market purchases change when the Transmission Projects are removed from the portfolio under the MM price-policy scenario. With fewer resources, market purchases increase by nearly 20 percent on an annual basis. This creates higher risk as the Company is forced to rely on market purchases at a time when there are increasing resource adequacy concerns throughout the western interconnect. This increased market and reliability risk is not reflected in the PVRR(d) results.

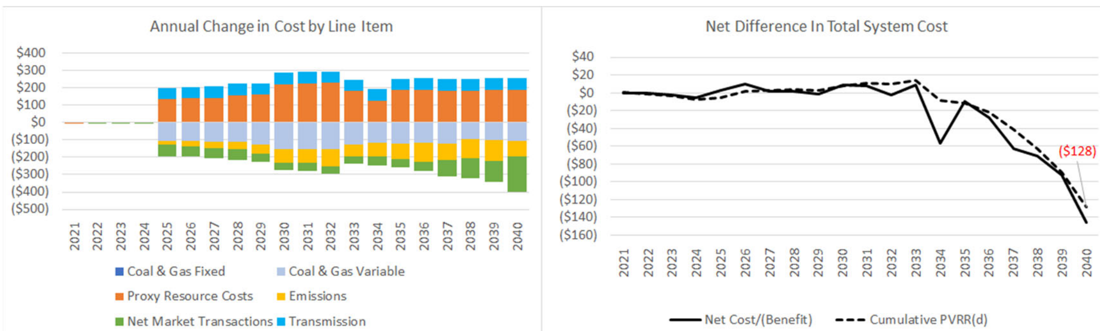
Figure 4. Changes in Market Purchases without the Transmission Projects



Q. How do system costs change with and without the Transmission Projects?

A. Figure 5 summarizes changes in system costs (conservatively assuming only the cost for a 230-kV alternative is unavoidable), based on ST model results using MM price-policy assumptions, when the Transmission Projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the Transmission Projects is $128 million higher cost than the portfolio with the Transmission Projects. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the Transmission Projects is $260 million higher cost than the portfolio with the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 5. Increase/(Decrease) in System Costs when the Transmission Projects are Removed from the Portfolio



Q. Is there incremental customer upside to the PVRR(d) results?

A. Yes. The PVRR(d) results presented in Table 3 do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by the Transmission Projects. Customer benefits for all price-policy scenarios would improve by approximately $42 million for every dollar assigned to the incremental RECs that will be generated through 2040. Beyond potential REC-revenue benefits, the economic analysis of the Transmission Projects does not reflect the reliability benefits that these investments will provide to the transmission system, which are described by Mr. Vail.

Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. The risk-adjusted PVRR(d) results show an increase in the benefits of the Transmission Projects when compared to the reported ST-model PVRR(d) results. This indicates that the Transmission Projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

ANNUAL REVENUE REQUIREMENT CALCULATIONS

Q. In addition to the modeling used to calculate present-value net benefits over a 20-year planning period, has PacifiCorp forecasted the change in nominal revenue requirement due to the Transmission Projects and the associated resources enabled by these projects?

A. Yes. The system PVRR from the Plexos model was calculated from an annual stream of forecasted revenue requirement over the period 2021 through 2040, consistent with the planning period in the 2021 IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, NPC, fixed operations and maintenance, PTCs, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of the Transmission Projects and associated resources, capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the Plexos model levelized?

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates. In the context of long-term resource planning that is conducted over a finite planning horizon, this can inappropriately favor less capital-intensive assets or assets with longer lives even if those assets might increase system costs over their remaining life.

Q. How did PacifiCorp forecast the annual revenue-requirement impacts of the Transmission Projects?

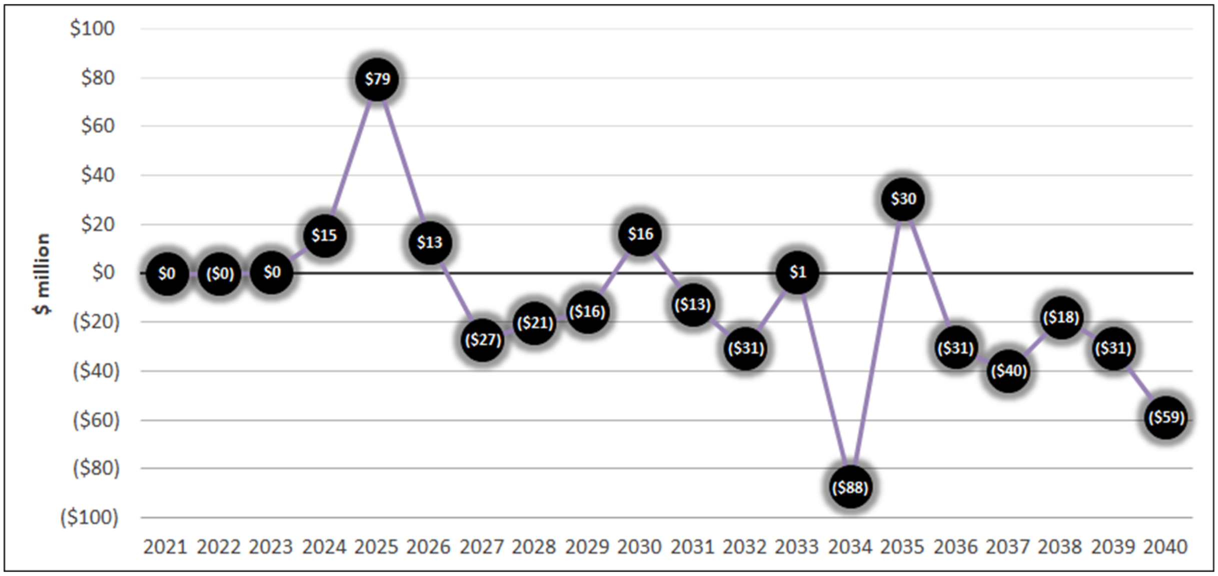
A. In the simulations that include the Transmission Projects and associated resources, the annual stream of levelized revenue requirement associated with the initial capital for the Transmission Projects and the associated resources, inclusive of assumed interconnection network upgrades, are recalculated as nominal revenue requirement through 2040, which aligns with the period for which modeled outcomes are available. Similarly, the annual stream of levelized revenue requirement associated with the initial capital for the transmission upgrades necessary to accommodate PacifiCorp's obligation to provide 500 MW of firm PTP transmission service under an executed, FERC-jurisdictional contract is recalculated as nominal revenue requirement through 2040. This stream of nominal costs represents revenue requirement that can be avoided with the Transmission Projects. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the Transmission Projects, the resources associated with the Transmission Projects, inclusive of assumed interconnection network upgrades, and the costs avoided by the Transmission Projects, represents the net system benefit caused by the Transmission Projects.

ANNUAL REVENUE REQUIREMENT CALCULATION RESULTS

Q. Please describe the change in annual nominal revenue requirement from the Transmission Projects.

A. Figure 6 shows the estimated change in annual nominal-revenue requirement due to the Transmission Projects for the MM price-policy scenario on a total-system basis (conservatively assuming that only the cost for a 230-kV alternative is unavoidable). The annual revenue requirement shown in the figure reflects all costs for the Transmission Projects and associated generation, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance expenses, the Wyoming wind-production tax, net of avoided transmission costs, transmission revenue credits, and PTCs. The project costs are netted against system impacts of the Transmission Projects and associated resources, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Transmission Projects.

Figure 6. Total-System Change in Annual Revenue Requirement Due to the Transmission Projects ($ million)



In 2025, the first full year the Transmission Projects are in service, the total-system nominal revenue requirement increases by $79 million. This figure rapidly declines and crosses over from a net increase in nominal revenue requirement to a decrease in nominal revenue requirement in 2027. Thereafter, the net revenue requirement impact as a result of the Transmission Projects trends toward increasing benefits over time as the new assets depreciate. In 2035, there is a modest increase in net revenue requirement following the expiration of PTC benefits for the BTA wind resources associated with the Transmission Projects. With on-going depreciation of the Transmission Projects and associated zero-fuel cost, zero-emission resources, annual revenue requirement benefits are expected to persist and grow beyond 2040.

SENSITIVITY ANALYSIS RESULTS

Q. Have you calculated how changes in the capital cost for the wind resources associated with the Transmission Projects might affect customer benefits?

A. Yes. Two of the six wind resources (approximately 36 percent on a capacity basis) are BTAs. For these two projects, a one percent increase in the initial capital costs would reduce PVRR benefits by $7.2 million. In the MM price-policy scenario, capital costs for the two BTA wind resources would need to increase by 36 percent to eliminate projected customer benefits on a risk-adjusted PVRR(d) basis.

Q. Have you calculated how changes in the capital cost for the Transmission Projects might affect customer benefits?

A. Yes. A one percent increase in the initial capital costs associated with the Transmission Projects would reduce PVRR benefits by $4.8 million. This estimate conservatively assumes that there is no change in transmission costs that will be avoided with the construction of the Transmission Projects. In the MM price-policy scenario, capital costs for the Transmission Projects would need to increase by 54 percent to eliminate customer benefits on a risk-adjusted basis. This demonstrates that the projected customer benefits are robust to potential variations in capital costs for the Transmission Projects, particularly when considering that the cost estimates used in the economic analysis of the Transmission Projects reflect PacifiCorp's experience with the recent construction of Gateway West Segment D.2 and the associated 230-kV network upgrades reflecting current market conditions.

Q. Did you perform a sensitivity study that evaluated any other alternatives to the Transmission Projects?

A. Yes. Consistent with the Commission's direction in the 2019 IRP[15] and 2020AS RFP,[16] the Company evaluated an alternative to Gateway South based on a transmission expansion case evaluated in the 2018-2019 biennial study cycle of the NTTG. This alternative (the "NTTG Alternative") is described by Mr. Vail. Consistent with this commitment, a sensitivity was performed, using MM price-policy scenario assumptions, to evaluate the NTTG Alternative. Table 5 summarizes how the assumptions for the NTTG Alternative compare to assumptions in the Company's analysis of the Transmission Projects.

Table 5. Assumptions in the NTTG Alternative Sensitivity

	CPCN Transmission Projects	**NTTG Alternative**
In-Service Date	12/31/2024	1/1/2027
In-Service Capital	$2.07 billion	$3.22 billion
Interconnection Capacity	2,030 MW	872 MW
Transfer Capability	1,700 MW from eastern WY to Mona UT	848 MW from eastern WY to Bridger; 562 MW from Bridger to Borah

Q. What are the results of the NTTG Alternative Sensitivity?

A. Table 6 shows the PVRR(d) impact of the NTTG Alternative, which excludes the Transmission Projects and associated new resources when using MM price-policy assumptions. In other words, the PVRR(d) results are calculated the same way that the PVRR(d) results for the price-policy scenarios are calculated except that the NTTG Alternative is assumed to replace the Transmission Projects. However, because the

[15] 2019 IRP Order at 23.
[16] Order Approving 2020 All Source RFP at 15.

NTTG Alternative cannot achieve an in-service date that aligns with the 13 executed transmission contracts described by Mr. Vail, the transmission investment that would otherwise be required for these executed contracts cannot be avoided. Considering that the NTTG Alternative is higher cost, enables less new resource interconnection at a later date (beyond the period where PTCs and the 30 percent ITC can be used to lower resource costs), and limits the incremental transfer capability out of eastern Wyoming, the NTTG Alternative does not deliver projected customer benefits. The NTTG Alternative is approximately $2 billion more costly for customers than the Transmission Projects proposed by the Company.

Table 6. (Benefit)/Cost of the NTTG Alternative ($ million)

Price-Policy Scenario	ST PVRR(d) Through 2040	ST Risk-Adjusted PVRR(d) Through 2040
MM	$1,958	$2,028

CONCLUSION

Q. Please summarize the conclusions of your direct testimony.

A. PacifiCorp's analysis shows that Gateway South is necessary and in the public interest, supporting the issuance of the requested CPCN. Under the MM price-policy scenario, the Transmission Projects produce significantly lower total system costs—ranging from $128 to $260 million when using the most conservative assumptions for avoided transmission and ranging from $610 million to $742 million when assuming the Transmission Projects are unavoidable. The Transmission Projects are also lower risk than alternative scenarios without the resources. Most notably, without the Transmission Projects and accompanying wind resources, the Company is forced to rely heavily on market purchases to serve load, which increases risk related to market volatility and creates reliability concerns given the region's well established resource adequacy concerns. By proactively constructing the Transmission Projects, the Company can not only save customers money (as evidenced by the savings in the MM price-policy scenario) but also reduce customer risk, which is a non-quantifiable benefit that strongly favors the Transmission Projects. The updated economic analysis of the Transmission Projects demonstrates that net benefits more than outweigh net project costs.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-1)
Docket No. 21-035-54
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Rick T. Link

Cost-and-Performance Assumption for the Transmission Projects

October 2021

REDACTED

Wind Resources

Facility Information and Up-front Capital (All Projects Qualify for 60% PTC)

	Capacity (MW)	Annual Energy (GWh)	Capacity Factor	In-Service Capital ($m)	In-Service Capital ($/kW)
Anticline (PPA)	100.5	[redacted]	[redacted]	$0	$0
Boswell Springs (PPA)	320	[redacted]	[redacted]	$0	$0
Cedar Springs IV (PPA)	350.4	[redacted]	[redacted]	$0	$0
Rock Creek I (BTA)	190	[redacted]	[redacted]	[redacted]	[redacted]
Rock Creek II (BTA)	400	[redacted]	[redacted]	[redacted]	[redacted]
Two Rivers (PPA)	280	[redacted]	[redacted]	$0	$0
Total	1,640.9	5,851	40.7%	$968	$590

Run-Rate Operating Costs ($m)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Wind Projects	$0.0	$0.0	$0.0	$0.03	$9.3	$9.5	$9.7	$9.7	$10.3	$10.9	$11.6	$12.2

	2033	2034	2035	2036	2037	2038	2039	2040
Wind Projects	$13.0	$13.9	$14.8	$15.7	$16.6	$17.6	$18.5	$19.5

Purchase Power Agreement ($m)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Wind Projects	$0.0	$0.0	$0.0	$8.3	$98.7	$99.3	$99.8	$100.8	$101.0	$101.6	$102.2	$103.2

	2033	2034	2035	2036	2037	2038	2039	2040
Wind Projects	$103.5	$104.1	$104.8	$105.8	$106.1	$106.8	$107.5	$108.6

Transmission

Transfer Capability and Up-Front Capital ($m)

	In-Service Capital ($m)	Transfer Capacity (MW)
Gateway South	$2,074.0	1,700*
Gateway West Segment D.1	$283.2	875
Avoided 230-kV Transmission	$1,385.9	500

*Modeled as 1,200 MW assuming a 500 MW point-to-point contract will consume a portion of the transfer capability.

Rocky Mountain Power
Exhibit RMP___(RTL-2)
Docket No. 21-035-54
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

PVRR(d) of the Transmission Projects

October 2021

ST Results ($ million)

Medium Gas, Medium CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,837	$0	$0	$0	$0	$193	$194	$199	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$397	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$327	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($748)	$0	$0	$0	$0	($130)	($130)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,345)	($0)	$0	($1)	($2)	($170)	($158)	($166)	($175)	($175)	($189)	($198)	($193)	($163)	($169)	($171)	($171)	($212)	($211)	($222)	($306)
Change in Emissions	($488)	$0	$0	$0	$0	($25)	($32)	($36)	($41)	($49)	($82)	($80)	($99)	($71)	($76)	($87)	($107)	($95)	($105)	($120)	($91)
Change in VOM & Driver Adjustments	($40)	($0)	$0	$0	($0)	($5)	($5)	($5)	($3)	($3)	($3)	($3)	($3)	$34	($16)	($16)	($16)	($16)	($16)	($16)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($4)	($0)	$0	$0	($1)	($3)	$0	($1)	($2)	($0)	$0	$0	$0	$0	$0	$0	$1	($0)	$0	$0	$0
Change in System Fixed Cos	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($128)	($0)	($1)	($2)	($6)	($12)	($4)	($12)	($12)	($16)	($5)	($6)	($17)	($5)	($70)	($24)	($42)	($76)	($85)	($107)	($160)
Risk Adjustment	($132)																				
Net (Benefit) /Cost with Risk Adjustment	($260)																				

Medium Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,811	$0	$0	$0	$0	$194	$195	$201	$215	$217	$225	$231	$234	$240	$167	$297	$301	$298	$300	$304	$309
New Wind Capital Cost	$398	$0	$0	$0	$0	$34	$35	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$326	$0	$0	$0	$0	$50	$50	$54	$52	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,304	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$149	$130	$132	$129	$129	$132	$134
PTC Credits	($746)	$0	$0	$0	$0	($129)	($129)	($134)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind [1]	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,305)	$1	$0	($1)	($1)	($163)	($163)	($168)	($171)	($172)	($202)	($197)	($203)	($150)	($152)	($153)	($167)	($190)	($202)	($215)	($251)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($49)	($0)	($0)	$0	($0)	($7)	($8)	($8)	($4)	($4)	($4)	($4)	($4)	$34	($16)	($17)	($17)	($17)	($17)	($17)	($16)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($4)	($0)	$0	$0	($1)	($3)	($0)	($1)	($1)	$0	($0)	$0	$0	($0)	$0	$0	($1)	$0	$0	$0	$0
Change in System Fixed Cos	($20)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	$30	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	$393	$0	($1)	($2)	($5)	$18	$21	$19	$33	$36	$62	$74	$70	$80	$23	$80	$68	$39	$28	$20	($12)
Risk Adjustment	($104)																				
Net (Benefit) /Cost with Risk Adjustment	$289																				

ST Results ($ million)

High Gas, High CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,808	$0	$0	$0	$0	$193	$194	$199	$214	$217	$225	$231	$234	$240	$167	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$396	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$327	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,304	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$149	$130	$132	$129	$129	$132	$134
PTC Credits	($749)	$0	$0	$0	$0	($131)	($131)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,697)	$0	$1	$1	($4)	($185)	($183)	($199)	($217)	($206)	($232)	($241)	($259)	($217)	($211)	($237)	($233)	($269)	($346)	($349)	($339)
Change in Emissions	($936)	$0	$0	$0	$0	($71)	($79)	($86)	($84)	($109)	($160)	($161)	($169)	($125)	($153)	($150)	($186)	($188)	($130)	($170)	($203)
Change in VOM & Driver Adjustments	($37)	($0)	$0	$0	$0	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($3)	$34	($16)	($16)	($16)	($17)	($17)	($19)	($18)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($8)	($3)	$0	$0	($1)	($3)	$0	($1)	($3)	$0	($0)	($0)	($2)	($0)	($0)	$0	$0	$0	$0	$0	$0
Change in System Fixed Cos	($20)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	$30	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($932)	($3)	($1)	($1)	($8)	($72)	($75)	($95)	($98)	($106)	($125)	($130)	($154)	($113)	($189)	($154)	($183)	($227)	($246)	($287)	($306)
Risk Adjustment	($168)																				
Net (Benefit) /Cost with Risk Adjustment	($1,100)																				

Low Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,838	$0	$0	$0	$0	$194	$195	$200	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$397	$0	$0	$0	$0	$34	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$326	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($748)	$0	$0	$0	$0	($130)	($130)	($134)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind [1]	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($128.78)	$0.00	$0.00	$0.00	($0.07)	($14.19)	($14.17)	($14.14)	($14.13)	($14.11)	($14.10)	($14.08)	($14.06)	($14.05)	($14.04)	($14.14)	($14.12)	($14.10)	($14.08)	($14.07)	($14.06)
Change in NPC	($948)	($0)	$0	$0	($2)	($105)	($109)	($115)	($120)	($119)	($141)	($141)	($147)	($118)	($123)	($122)	($130)	($151)	($159)	($165)	($200)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($40)	$0	$0	$0	$0	($4)	($5)	($6)	($3)	($2)	($2)	($3)	($3)	$34	($17)	($17)	($17)	($17)	($17)	($17)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($5)	($0)	$0	$0	($2)	($3)	($0)	($1)	($2)	($0)	($0)	$0	$0	($0)	$0	($0)	($0)	$0	$0	$0	$0
Change in System Fixed Cos	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	$755	($0)	($1)	($2)	($6)	$79	$77	$74	$84	$90	$125	$132	$128	$111	$52	$111	$105	$79	$72	$69	$38
Risk Adjustment	($85)																				
Net (Benefit) /Cost with Risk Adjustment	$670																				

SC-GHG

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,836	$0	$0	$0	$0	$192	$194	$199	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$396	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$328	$0	$0	$0	$0	$51	$52	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($750)	$0	$0	$0	$0	($131)	($131)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($2,129)	$0	($1)	($6)	($4)	($217)	($230)	($243)	($260)	($296)	($363)	($350)	($357)	($286)	($288)	($292)	($304)	($380)	($270)	($291)	($359)
Change in Emissions	($1,919)	($0)	$3	$5	($3)	($317)	($264)	($266)	($245)	($246)	($286)	($286)	($296)	($198)	($218)	($229)	($260)	($257)	($274)	($274)	($260)
Change in VOM	($30)	$0	($0)	$0	$0	($1)	($1)	($2)	($2)	($2)	($1)	($2)	($2)	$35	($16)	($16)	($15)	($22)	($15)	($14)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($236)	($0)	$0	($15)	($3)	($67)	($38)	($16)	($25)	($4)	($126)	$0	$0	$0	($0)	$0	($1)	($233)	$0	$0	$69
Change in System Fixed Cos	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($2,568)	($1)	$1	($18)	($13)	($412)	($343)	($331)	($322)	($336)	($508)	($363)	($377)	($254)	($331)	($287)	($328)	($646)	($312)	($328)	($312)
Risk Adjustment	($251)																				
Net (Benefit) /Cost with Risk Adjustment	($2,819)																				

CERTIFICATE OF SERVICE

Docket No. 21-035-54

I hereby certify that on October 7, 2021, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services	
Michele Beck	mbeck@utah.gov
ocs@utah.gov	
Division of Public Utilities	
dpudatarequest@utah.gov	
Assistant Attorney General	
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Robert Moore	rmoore@agutah.gov
Victor Copeland	vcopeland@agutah.gov
Rocky Mountain Power	
Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com utahdockets@pacificorp.com
John Hutchings	john.hutchings@pacificorp.com

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations