REDACTED
Rocky Mountain Power
Docket No. 17-035-40
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Direct and Rebuttal Testimony of Rick A. Vail

January 2018

Q. Are you the same Rick A. Vail who previously provided direct testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental direct and rebuttal testimony?

A. Based on the results of the 2017R Request for Proposals ("RFP"), in my supplemental direct testimony, I update the status of the Aeolus-to-Bridger/Anticline Line[1] and network upgrades ("Transmission Projects") that support the Company's decision to construct or procure four new wind resources ("Wind Projects") (collectively, the "Combined Projects"). I explain the important progress the Company has made on the Transmission Projects, as well as their decreasing risk.

In my rebuttal testimony, I respond to the direct testimony of Utah Division of Public Utilities ("DPU") witnesses Mr. Robert A. Davis and Mr. Daniel Peaco, Office of Consumer Services ("OCS") witness Mr. Philip Hayet, and Utah Association of Energy Users and Utah Industrial Energy Consumers witness Mr. Bradley G. Mullins.

Q. Please summarize your testimony.

A. I address the following key issues for the Transmission Projects:

- An update on the status of:
  - Expected design and cost;
  - Engineering, Procurement, and Construction ("EPC") contracts;
  - Required permits at the federal, state, and local level; and
  - The required power system analyses and easements.

[1] As defined in my direct testimony at page 2, lines 29-37.

- The necessity of these projects to reduce line losses and derates along with dispatching of Company-owned resources.
- Technical analysis demonstrating that the Company's Aeolus-to-Bridger/Anticline Line will enable interconnection of up to 1,270 MW of additional resources and increase transfer capability by 750 MW from east to west across Wyoming.
- Mitigation of risks to minimize costs and project delays due to:
  - The permitting process and the Company's plan for obtaining required permits before construction;
  - Obtaining the required easements; and
  - Construction delays (EPC contracts and mitigation for meeting construction deadlines).
- Relevant Open Access Transmission Tariff ("OATT") and Federal Energy Regulatory Commission ("FERC") precedent confirming the reasonableness of the Company's assumptions regarding revenues from third-party customers.
- The Company's need for timely resource approval to maintain project timelines.

SUPPLEMENTAL DIRECT TESTIMONY

UPDATE ON THE TRANSMISSION PROJECTS

Q. Since the initial filing, has the Company maintained the project schedule and cost estimates for the Aeolus-to-Bridger/Anticline Line?

A. Yes. The Company has made significant progress and is on track to meet its development schedule at or below the costs estimated in its direct filing.

Q. Did the results of the 2017R RFP affect the costs or design of the Aeolus-to-Bridger/Anticline Line?

A. No. The results of the 2017R RFP did not affect the estimated costs or the design of the Aeolus-to-Bridger/Anticline Line. As discussed below, the Company's continued project development efforts have confirmed the cost estimates included in the initial filing.

Q. Have the network upgrades described in your direct testimony changed because of the final shortlist Wind Projects from the 2017R RFP?

A. Yes. There are changes to the network upgrades resulting from the Wind Projects chosen for the final shortlist for the 2017R RFP. The Wind Projects are four facilities in Wyoming totaling approximately 1,170 MW—McFadden Ridge II, TB Flats I and II, Cedar Springs, and Uinta.

Q. Please describe the updated network upgrades required to interconnect the Wind Projects.

A. The 230 kV network upgrades for the McFadden Ridge II and TB Flats I and II projects that were identified in my direct testimony are still necessary to interconnect these Wind Projects because they were selected for the 2017R RFP final shortlist.[2] In addition, the McFadden Ridge II project will require a new three-breaker 230 kV point-of-interconnection ring-bus substation on the High Plains-to-Foote Creek 230 kV line, roughly two miles southwest of High Plains substation, as shown in Exhibit

[2] Details regarding these network upgrades can be found in my direct testimony and exhibits (page 2, lines 38-48). The Ekola project that was also included as a benchmark resource in the initial filing did not require network upgrades to interconnect, and therefore all network upgrades discussed in my direct testimony were related to the McFadden Ridge II and TB Flats I and II projects.

RMP___(RAV-1SD). There are also additional network upgrades required for the other projects that were selected through the 2017R RFP.

To interconnect the Cedar Springs project, the Company must install two 230 kV (3000 ampere) breakers and two line positions with associated switches at the Windstar substation. The Company must also install high-speed relaying to switch off the shunt capacitor banks at the Riverton 230 kV bus, which are required for high-voltage conditions, and rebuild approximately 56 miles of the Dave Johnston-Amasa-Difficulty-Shirley Basin 230-kV line with 2-1272 bundled conductor.

To interconnect the Uinta project, the Company must construct a new three-breaker 138 kV point-of-interconnection ring-bus substation southwest of the Whitney Canyon Tap (near structure 116), with associated switches and line terminations. The Company must also reconductor approximately 13.7 miles of the Q0715 - Railroad 138 kV line with 1-1272 ACSR/phase (line has 1-795 ACSR/phase), and modify the existing Naughton remedial action scheme ("RAS") to allow redundant communication to the project.

RMP___(RAV-1SD) details the specifics of these additional network upgrades.

Q. What are the updated costs for the network upgrades?

A. Confidential Table 1 summarizes the updated costs for the network upgrades:

Confidential Table 1

Network Upgrades	
ITEM	**VALUE**
Transmission Line	$ [redacted]
Substation	$ [redacted]
Engineering	$ [redacted]
Right-of-Way Acquisition	$ [redacted]
PM/Environmental/Support	$ [redacted]
Indirects	$ [redacted]
TOTAL	**$** [redacted]

Q. Have these costs been included in the updated economic analysis included in Mr. Link's testimony?

A. Yes.

Q. Why did the network upgrade costs increase by approximately [redacted] million compared to the Company's initial estimate?

A. The selection of the Cedar Springs and Uinta projects to the 2017R RFP shortlist required additional network upgrade costs that were not included in the original estimate. Notably, however, although the network upgrade costs increased relative to the initial filing, the overall costs of the Combined Projects remains roughly unchanged even though customers are now receiving substantially more capacity for the same overall project cost of approximately $2 billion, as discussed further by Mr. Link in his supplemental direct testimony.

Q. Will these additional network upgrades delay the completion of the Transmission Projects?

A. No. The types of additional upgrades needed are fairly routine projects that the Company performs in the ordinary course of business, and they can be completed well

before the end of 2020.

Q. Have you included the information required by Utah Admin. Code R746-440-1(1) for the new facilities described above.

A. Yes. Exhibit RMP___(RAV-1SD) includes the additional relevant information required for approval of a voluntary resource decision.

Q. Please provide a status update on the design of the Transmission Projects.

A. Currently, both the Aeolus-to-Bridger/Anticline Line and the 230 kV network upgrades are in the detail design phase. For the 500 kV facilities, the major effort is focused on two key elements: (1) micro-siting structures; and (2) structure design.

Micro-siting structures involves confirming the precise structure locations and associated access roads to accommodate features such as pipelines, fiber-optic cables, and other utilities, along with micro-siting to avoid sensitive biological or cultural features.

The structure-design process focuses on selecting the tower and foundation design that will be used. Before filing the initial request, the Company decided it could use a new tower design that would significantly reduce the structures' weight, and therefore cost, as compared to the tower design used in other segments of the Energy Gateway project. The Company is in the process of developing and testing the revised structures and expects to complete this by summer 2018, in line with the overall EPC schedule. The Company is currently completing the initial design phase, the first prototype has begun the fabrication process, and tower testing is scheduled to begin mid-first-quarter 2018. Development efforts to date have confirmed the baseline assumptions included in the design and cost basis of the initial filing.

In addition, the Company completed a geotechnical program during summer 2017 to further aid the EPC contractors in bid preparation and reduce the risk assumptions associated with the foundation design. The overall 500 kV transmission design package is on track to be complete by April 2018.

Q. What is the status of the 500 kV substation design work?

A. The 500 kV substation design work is on schedule. The Company has focused recent efforts on thoroughly analyzing the precise location and space requirements for each new substation. This has led to a reduction in the initial space requirements and allowed for a balanced cut-and-fill design to reduce the cost of importing high-cost fill materials. At the Jim Bridger substation, design optimization efforts will facilitate construction of the new line-termination bay while minimizing disruptions to the existing facility. The substation design necessary for competitive market EPC bidding is anticipated to be completed by April 2018.

Q. What is the status of the network upgrade facilities?

A. Design work for the 230 kV network upgrades is also ongoing. The Company has selected the proposed line route, after considering field surveys for biological and cultural constraints, as well as incorporating landowner comments. Exhibit RMP___(RAV-2SD) contains topographical maps for the proposed line route. Structure design will be based upon the Company's standard design steel H frames. The Company will begin design work for the 230 kV substations in early 2018. All design work for the network upgrade facilities will be completed by fall 2018, to allow for the competitive market procurement process to support a 2019 construction period.

Q. What is the current status of the EPC contract for the Aeolus-to-Bridger/Anticline Line?

A. The Company is currently in a competitive selection process for an EPC contractor for the Aeolus-to-Bridger/Anticline Line. Because the line is approximately 85 percent of the total costs of the Transmission Projects, the selection of the EPC contractor will be a significant milestone in confirming final project costs. The preliminary results of this process have confirmed the project cost estimates included in the initial filing.

Q. Please provide more detail on the status of the EPC contracts for the Transmission Projects.

A. The Company has engaged with eight transmission line contractors to secure Master Service Agreement Terms and Conditions that will apply to the Transmission Projects. The contractors represent some of the leading engineering and construction companies in the country. Negotiations are currently ongoing to finalize these terms and conditions in January 2018.

Concurrent with these activities, the Company issued a request for detailed technical information to the same contractors. This request requires contractors to provide detailed project plans, resource profiles, schedules and cost data. The responses will be analyzed to develop a shortlist of contractors, based on a combination of cost and viability of the overall project approach, for a final pricing event in the summer 2018. Contractor responses were received December 11, 2017. The data within the responses will also be used to inform the analysis being performed for the Wyoming Industrial Siting Permit application. The EPC contracts for the Aeolus-to-Bridger/Anticline Line remain on track to be in place by October 2018.

For the 500/345-kV substation scope of work, the Company is currently preparing a terms-and-conditions RFP that will be issued by early February 2018 to up to six qualified contractors who will be responsible for full EPC services for the 500/345-kV substations. This RFP will also request budgetary price information. The Company intends to negotiate EPC contract terms and conditions before final pricing to expedite final contract negotiations in fall 2018. A final price bid event will be issued to all six companies in the summer of 2018.

For the network upgrades, the Company intends to competitively source both the transmission line and substation construction via existing term "Line Service Agreements" the Company holds with over one dozen qualified contractors capable of working in Wyoming. The Company may acquire major substation equipment as a direct purchase through a competitive RFP to qualified vendors. The network upgrade work is on schedule to be procured in late 2018 with main construction anticipated during 2019.

Q. What is the status of the permits required for construction of the Transmission Projects?

A. The Company has been working with various agencies and stakeholders to obtain the final permits necessary to construct the facilities and the Company's permitting activities remain on schedule. A summary of key items is presented below:

Section 106 Consultation, National Historic Preservation Act: Field surveys were completed during the summer of 2017. The final class III cultural report was submitted to the Bureau of Land Management ("BLM") on December 15, 2017. Programmatic Amendment Agreement has been signed and approved by the Bureau of

Land Management and the State Historical Preservation Office. The Umbrella Historic Properties Treatment Plan (which includes all Energy Gateway West in Wyoming) has all of the approvals required and the project specific Historic Properties Treatment Plan will be developed and submitted after acceptance of the Class III cultural report, expected February 2018. Final approval by the Wyoming State Historic Preservation Office of the Historic Properties Treatment Plan is expected by mid-August 2018.

Plan of Development: Work continues in close cooperation with the BLM. Initial updated draft sections have been provided to the BLM, with comments received. The Plan of Development is on schedule to be completed by May 2018 to support the EPC procurement schedule. Final Plan of Development mapping will be completed by the end of 2018 after including updated data from the 2018 field survey season.

Clean Water Act Sections 401: Wyoming Department of Environmental Quality ("WYDEQ") Water Quality Division ("WQD") has categorically-certified the majority of the 2017 USACE Nationwide Permits on non-Class 1 waters in Wyoming with the expectation that applicants must comply with the permit's terms and conditions, including permit specific 401 Certification conditions for the certification to be valid. These categorically-certified permits do not require an individual 401 Certification by the WYDEQ/WQD. The Transmission Projects require that a section 404, nationwide permit 12 be obtained. This will meet the requirements under the State of Wyoming for Section 401 certification.

Section 404/NWP 12: The Transmission Projects have completed all wetland delineations to determine impacts. These potential impacts are being reviewed for avoidance via detail design reviews. The Company will submit its pre-construction

notification to certify the project does not exceed greater than 0.1 acre of permanent impact at any one delineated wetland area. This is on schedule for approval in May 2018.

Wyoming Industrial Siting Permit: The Company held an initial meeting with the WYDEQ with respect to the Wyoming Industrial Siting Permit and the WYDEQ determined the jurisdictional determination first recorded in 2012 is still valid. The Company is preparing an application for submission by the end of June 2018. The 135 day review period as described in the Wyoming Administrative Rules, Chapter 35, will therefore conclude with a decision due by mid-November 2018.

Carbon County Conditional Use Permit ("CUP"): The Company held a preliminary meeting with Carbon County to discuss the requirements of the CUP application. The Company is preparing the application for a May 2018 submission with an August 2018 decision.

Q. What is the status of the technical studies that are necessary to support the Transmission Projects?

A. The Company performed numerous technical studies that show the benefits and reliability improvements resulting from the Transmission Projects. As with any large-scale transmission project, the Company continues to perform additional technical studies. Confidential Exhibit RMP___(RAV-3SD) provides a detailed outline of the studies performed so far and a description of the additional studies that will be performed, along with the timing of the additional studies.

In October 2017, the Company completed detailed studies, including power flow and stability analysis, evaluating a wide range of operating conditions. This study,

the Preliminary Aeolus West Transmission Path Transfer Capability Assessment ("Preliminary Study Report"), is attached to this testimony as Exhibit RMP___(RAV-4SD).

Preliminary North American Electric Reliability Corporation ("NERC") FAC-013-2 Transmission Assessment studies are currently underway for the Aeolus-to-Bridger/Anticline line and are expected to be finalized in 2020. The first set of studies to be included in this process has already been completed and showed an increase of transfer capability of 750 MW from east to west across Wyoming. Technical analysis shows the Aeolus-to-Bridger/Anticline line increases the system's stiffness factor sufficiently to enable interconnection of up to 1,270 MW of additional resources. All of the technical study work completed to date continues to support the initial assumptions for the Transmission Projects, the facilities identified, and the benefits that the Transmission Projects will provide.

Q. What is the status of the Company's acquisition of rights-of-way necessary for the Transmission Projects?

A. The Company has contacted all landowners where easements for access or transmission rights-of-way (or both) are required. To date, 24 offers of options for rights-of-way have been issued to landowners. Four landowners have accepted and three additional landowners have provided counteroffers. All remaining offers for the 500 kV project will be issued by January 31, 2018. The acquisition of rights-of-way remains on track to support the planned construction start date of April 1, 2019.

REBUTTAL TESTIMONY

NECESSITY OF THE TRANSMISSION PROJECTS

Q. Mr. Davis has concluded that if the Wind Projects are not approved, there is no need for the Transmission Projects. (Davis Direct, lines 36-39.) Do you agree?

A. No. There is an independent need for the Aeolus-to-Bridger/Anticline Line even if the new Wind Projects are not constructed because it will improve system performance and reliability and directly serve customers. To be clear, even if the Wind Projects are not approved, the Company's—and the region's—long-term transmission plans still call for the construction of the Aeolus-to-Bridger/Anticline Line (and some of the network upgrades) by 2024. Thus, the Company will need to construct this transmission line in the near future. The question is whether it is built in 2020 when PTC-eligible wind can offset the costs and produce net benefits for customer, or in 2024 at full cost to customers.

Q. Does Mr. Davis agree that the Transmission Projects are necessary if the Wind Projects are approved?

A. Yes. (Davis Direct, lines 306–308.)

Q. What is the current status of the Company's eastern Wyoming transmission system?

A. The Company's eastern Wyoming transmission system is severely restrained and experiences voltage-support issues. While the Company is in compliance with all NERC and Western Electricity Coordinating Council ("WECC") reliability standards, the stiffness factor (measurement of a transmission system's ability to control voltage within acceptable limits) in eastern Wyoming is such that new resources cannot be

connected to the system, increasing the risk of voltage swings outside acceptable limits in an outage condition. This system condition also limits the ability to schedule outages for segments of the transmission system to perform routine maintenance.

Q. Do these general conditions apply specifically in the area where the Transmission Projects will be constructed?

A. Yes. The same constraints and stiffness-factor limits present in eastern Wyoming generally are present along the TOT 4A transmission path where the Transmission Projects will be constructed. Because of the constraints and the stiffness-factor limit, new resources cannot be connected behind the path (*i.e.*, east of the path). Further, an outage of a TOT 4A transmission element results in a path derate to prevent a thermal or voltage system violation and maintain system reliability. Existing generation must often be curtailed to operate within derated path limits, which is a curtailment in firm transmission rights used to serve customer load.

Q. Mr. Davis discusses guidelines provided by the U.S. Department of Energy ("USDOE") related to transmission planning and construction that informed DPU's analysis of the Transmission Projects. (Davis Direct, lines 153–159.) What are the guidelines identified by Mr. Davis?

A. Mr. Davis identified three guidelines. The Company must: demonstrate a need for the Transmission Projects; determine who pays for the Transmission Projects; and site and permit the Transmission Projects.

Q. What did DPU conclude based on the application of the USDOE transmission planning guidelines?

A. According to Mr. Davis, DPU concluded that the "Company planned the transmission

projects . . . for reliability and resiliency to support the new wind generation" and that "with the new wind generation, the proposal fits [USDOE's] guidelines." (Davis Direct, lines 170–173.)

Q. Do you agree with Mr. Davis' conclusion?

A. Yes, but not his rationale. As noted above, there is a need for the Transmission Projects, with or without the Wind Projects.

Q. Mr. Davis also testifies that even with the Transmission Projects, the Company's Wyoming transmission system will still be constrained. (Davis Direct, lines 199–202.) Do you agree?

A. Yes. The Company has never indicated that the Transmission Projects alone will resolve all the existing congestion in Wyoming. But the construction of the Transmission Projects will relieve existing congestion and allow greater grid flexibility in eastern Wyoming, and achieve these benefits with limited rate impact because of the PTCs generated by the Wind Projects.

Q. Mr. Mullins claims the Aeolus-to-Bridger/Anticline line may not be the best solution for addressing transmission needs in the West. (Mullins Direct, page 21, lines 6–7.) How do you respond?

A. Mr. Mullins provides no substantive analytic support for his contention. Instead, Mr. Mullins implies the Aeolus-to-Bridger/Anticline Line was developed outside of the intra-regional transmission planning process required by FERC's Order No. 1000, but this implication is wrong. Contrary to this implication, the Aeolus-to-Bridger/Anticline Line is an integral component of the intra-regional transmission plan developed by the Northern Tier Transmission Group ("NTTG") in accordance with FERC's Order No.

1000. In fact, the current transmission system master plan for Wyoming calls for the construction of facilities associated with Energy Gateway, specifically Energy Gateway West and Energy Gateway South. The Aeolus-to-Bridger/Anticline line is a subset of the Energy Gateway West project.

The Company has identified these projects in long-term transmission plans to: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection of new generation resources and enabling more efficient dispatch of and greater flexibility in managing existing resources; (2) provide critical voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses. As a part of the Combined Projects, however, customers can economically obtain the much-needed support and benefits the Transmission Projects will bring to the Company's existing transmission network.

Q. Has any other party provided testimony addressing how the Transmission Projects fit into the regional transmission plan?

A. Yes. Mr. Davis specifically acknowledges that the NTTG has indicated that the Wyoming transmission system requires "significant reinforcements" to "handle both existing and future planned wind resources while maintaining all other Wyoming area generating resources at their typical high capability in an export scenario." (Davis Direct, lines 101-104.)

Q. Mr. Mullins also claims the Company should invest in transmission projects that improve reliability, rather than projects that are driven by economics. (Mullins Direct, page 21, lines 7-10.) How do you respond to this claim?

A. Mr. Mullins does not dispute the Company's extensive evidence that the Aeolus-to-

Bridger/Anticline Line will, in fact, improve reliability and relieve existing congestion on the eastern Wyoming transmission system. Thus, by his own standards, the Aeolus-to-Bridger/Anticline Line is the type of transmission investment that should be pursued.

Q. Will the Transmission Projects also increase system efficiency?

A. Yes. The addition of a transmission line together with an existing line or path will reduce the impedance of the path, resulting in overall reduced energy line losses. Line losses before and after construction of the Transmission Projects were compared, with the difference being the line savings attributed to the Transmission Projects. Reduced line losses mean more efficient delivery of energy and capacity at reduced costs with or without the addition of new generation resources providing additional operational flexibility of existing resources.

Q. Have there been previous investments in transmission facilities along the TOT 4A path?

A. Yes. Since the time that the TOT 4A transmission path was initially defined, a significant number of transmission additions and modifications have been made to the Wyoming transmission system to increase the capacity on this path, including the addition of new transmission lines (Spence-to-Mustang in 1991; Dave-Johnston-Casper rebuild in 2010; and Sheridan-Dry-Fork-to-Hughes/Carr-Draw in 2010-11), adding shunt capacitors for voltage support, implementation of dynamic line ratings (Platte-to-Miners 230-kV line in 2013), and addition of a synchronous condenser (at Standpipe in 2016).

As significant new facilities were added, WECC path-rating studies have been performed to increase the rating of the path. The last set of path-rating studies were

completed April 17, 2013, with the granting of Phase 3 status by the WECC planning coordination committee ("PCC"). These additions and subsequent path ratings have supported the addition of resources behind the path to the point today where the stiffness factor and the path rating cannot support additional resources without infrastructure additions. Generation interconnection studies have shown that additional resources cannot be reliably interconnected without the addition of transmission infrastructure.

Q. Mr. Hayet argues that the Company's interconnection studies for the Wind Projects assumed that additional Energy Gateway segments would be constructed to facilitate interconnection of the Transmission Projects. (Hayet Direct, lines 743-753.) How do you respond?

A. The Company acknowledges that prior interconnection studies used Energy Gateway "full-build-out" assumptions. The Company is currently revising applicable interconnection studies to recognize that the Energy Gateway segments will be constructed in phases.

Q. Mr. Hayet also claims that the Combined Projects may not be the least-cost, least-risk resources because the early retirement of the Dave Johnston plant may free up sufficient transmission that another resource option is more economic than the Combined Projects. (Hayet Direct, page 33, lines 679-695.) How do you respond?

A. Mr. Hayet correctly testifies that retiring the 762 MW Dave Johnston plant will not, on its own, obviate the need for the Aeolus-to-Bridger/Anticline transmission line because the Dave Johnston plant provides critical voltage support to the 230-kV transmission system and without that support, the Company could not integrate the Wind Projects

(or any other new resources). Mr. Hayet suggests, however, that early retirement, coupled with some other solution to solve the voltage support issues, may be lower cost than the Aeolus-to-Bridger/Anticline transmission line.

Based on feedback received during the 2017 IRP review process in Oregon, the Company initiated transmission studies to provide additional clarity on whether an early retirement of the Dave Johnston plant with the addition of new wind resources could be a viable alternative to the Aeolus-to-Bridger/Anticline transmission line. This analysis, which is being reviewed by an independent third-party, identified that major reinforcement projects would be required on the 230 kV system to operate the transmission system reliably and would eliminate the option of upgrading to 500 kV in the permitted rights of way. These studies indicate the reinforcement projects would be more costly than the Aeolus-to-Bridger/Anticline line and result in less incremental transfer capability out of eastern Wyoming.

Q. Are there any other concerns associated with the early retirement of the Dave Johnston plant?

A. Yes. The Dave Johnston plant is one of the lowest variable-cost assets on the Company's system and operationally, provides flexibility that facilitates the Company's ability to import low-cost renewable energy from California through the energy imbalance market (EIM). The plant also provides significant system capacity needed to satisfy the Company's 13 percent target planning reserve margin and provides fault current support to maintain "stiffness" of the grid which is necessary to support system voltages. If Dave Johnston retired at the end of 2020 (approximately three years out), there would be limited time to procure potential replacement resource alternatives

capable of delivering energy and capacity benefits comparable to those provided by the Dave Johnston plant and could necessarily increase the Company's reliance on market purchases. Retiring Dave Johnston by the end of 2020 would also create substantial upward pressure on customer rates due to the accelerated depreciation resulting from early retirement.

TRANSMISSION STUDY PROCESS

Q. Mr. Peaco criticizes the Company's Preliminary Study Report. (Peaco Direct, lines 528-535.) What did that study conclude?

A. The Preliminary Study Report concluded that the Transmission Projects will allow the interconnection of the Wind Projects and increase the transfer capability from east to west across Wyoming by 817.5 MW. In addition, the Preliminary Study Report concluded that, with the addition of the Transmission Projects to the Wyoming transmission system, the system performance will meet all NERC and WECC performance criteria.

Q. What concerns did Mr. Peaco raise?

A. Mr. Peaco identified three concerns. First, Mr. Peaco claims that the assumptions and methods used in the Preliminary Study Report are problematic. Second, Mr. Peaco claims that the Preliminary Study Report does not support the Company's claim that 1,270 MW of new wind resources can be integrated. Third, Mr. Peaco claims that the Preliminary Study Report is an initial report, and the actual WECC path transfer limit will not be known until after construction begins.

Q. Addressing Mr. Peaco's first concern, what assumptions does Mr. Peaco challenge?

A. Mr. Peaco argues that the Company assumed that multiple Remedial Action Schemes ("RAS") are necessary to resolve the reliability problem created by the integration of large amounts of new wind generation. (Peaco Direct, lines 546-548.) Mr. Peaco claims that planning on using RAS does not reflect prudent system operation.

Q. How do you respond?

A. A RAS is a tool recognized by NERC to protect the reliability and integrity of the Bulk Electric System ("BES"). There are specific NERC standards in place to ensure that RAS do not introduce unintentional or unacceptable reliability risks to the BES, specifically PRC-012-2, which requires the RAS-entity to provide the RAS information and documentation to the reliability coordinator before placing a new or functionally modified RAS in service or retiring an existing RAS. The Company's use of RAS for generator tripping conforms to the NERC standards and is not imprudent or unreasonable. It is important to note that the RAS the Company is proposing will not trip load in the area. The RAS will be a generator tripping scheme that will take wind resources offline only if a transmission facility outage condition occurs during periods of high system transfers.

Q. Mr. Peaco also claims that the Preliminary Study Report unreasonably relies on the assumption that it is acceptable to severely limit the TOT 4B path to integrate the new wind resources. (Peaco Direct, lines 556–558.) Please respond.

A. Studies are ongoing for varying TOT 4B transfer levels, and it is not anticipated that TOT 4B will be severely limited, or even limited at all. The Preliminary Study Report is just one set of assumptions, and other flow levels will continue to be studied to

determine the full range of simultaneous operating interactions (nomograms) between the TOT 4B and Aeolus West paths, just as with the TOT 4B and TOT 4A paths.

Q. With respect to his second concern, Mr. Peaco argues that the customer benefits of the Combined Projects would be eliminated if transmission limitations caused even a relatively small reduction in the amount of wind resources that the Company acquires. (Peaco Direct, lines 582–585.) Are you confident that the Transmission Projects will allow the interconnection of the Wind Projects?

A. Yes. Certain assumptions were made about the location of the proposed new wind generation in the Preliminary Study Report, and these assumptions proved reasonable based on the Wind Projects selected through the 2017R RFP. Based on this study and ongoing study efforts, the Company has a high degree of confidence that it can interconnect the amount of wind contemplated. Depending upon the ultimate size, technology and location of new generation, interconnection of an even larger amount of wind resources may be feasible.

Q. Mr. Peaco claims that the Company's use of dynamic line ratings for the Platte-Standpipe 230-kV segment, rather than normal and emergency line ratings, was improper. (Peaco Direct, lines 593–594.) How do you respond?

A. I disagree that the Company's use of dynamic line ratings was improper. If dynamic line-rating devices are installed on a line, as they are on the Platte-Standpipe 230 kV segment, the Company can properly exercise its engineering judgment to use dynamic line ratings in planning studies. The Company monitored and studied conditions for application of the dynamic line rating, (*i.e.*, ambient temperature, wind speed, etc.), in real-time before for determining the appropriateness and implementation of the

dynamic line rating on the Platte-Standpipe 230-kV line. Dynamic line ratings have been used in previous WECC path-rating reports, including the Comprehensive Progress Report ("CPR") for the TOT 4A (Path 37) and TOT 4B (Path 38) Path Rating Increase Project, which was granted a Phase 3 rating by the WECC Planning Coordination Committee ("PCC") on April 17, 2013.

Q. Mr. Peaco claims that the Preliminary Study Report improperly applied a different assumption from the existing path definition by moving the Platte-area load to the east of the Aeolus West cut-plane. (Peaco Direct, lines 603-604.) How do you respond?

A. This claim is incorrect. The definition of the Aeolus West path in the Preliminary Study Report is consistent with that previously defined in the Energy Gateway West WECC path-rating process.

Q. Mr. Peaco claims that the Preliminary Study Report evaluated 1,169 MW of new wind resources and therefore does not demonstrate that the Transmission Projects will allow the interconnection of 1,270 MW of new wind resources. (Peaco Direct, lines 625-627.) How do you respond?

A. The Preliminary Study Report included a scenario with the addition of 1,270 MW of wind as a sensitivity analysis, set forth in section 5 of the report. In addition, the final shortlisted Wind Projects have a total capacity of 1,170 MW.

Q. Mr. Peaco is also concerned that the assumptions used in the Preliminary Study Report will not be accepted by WECC and that WECC's path rating study will not be completed until the Transmission Projects are under construction. (Peaco Direct, lines 647-658.) Is this concern valid?

A. No. At the March 30, 2010 Gateway West and Gateway South combined project review, meeting participants approved the Gateway Phase 2 Study Plan and agreed that incremental limitations for transmission segments added between states will be addressed through System Operating Limit ("SOL") studies. This same process was previously followed and successfully demonstrated by the Bonneville Power Administration and Avista for the West-of-Hatwai Expansion project. In addition to SOL studies, which will be completed before the project goes into service, PacifiCorp will be performing FAC-013-2 Transfer Capability Assessment studies, which it will share with other utilities and WECC. These studies are scheduled for completion by October 2019, more than one year before the project in-service date.

RISK MITIGATION OF TRANSMISSION PROJECTS

Q. Mr. Hayet and Mr. Peaco are concerned that the Transmission Projects will not be completed by the end of 2020 and may cost more than expected. (Hayet Direct, lines 449-451; lines 470-485; Peaco Direct, lines 863-874; lines 956-958.) Mr. Mullins also express a concern over the risk of cost overruns. (Mullins Direct, page 46, lines 13-17.) Please describe the Company's experience mitigating these types of transmission project risks.

A. In the past five years, the Company has completed two significant and similar Energy Gateway transmission projects: (1) the 100-mile 500/345-kV Mona-to-Oquirrh

transmission line; and (2) the 170-mile 345-kV Sigurd-to-Red-Butte transmission line. Similar to the Aeolus-to-Bridger/Anticline line, both projects required a NEPA-compliant environmental impact statement, including a record of decision, plan of development, and right-of-acquisition process. Using its expertise in utility resource development and project management, the Company delivered both the Mona-to-Oquirrh and Sigurd-to-Red-Butte transmission lines within the cost estimates used in the approval processes and on time. Table 2 below summarizes the actual project performance relative to the filing information:

TABLE 2

	Original Filing Information				ACTUAL DATA	
PROJECT	**REF**	**Date of Application**	**COST ($000,000s)**	**In Service**	**COST ($000,000s)**	**In Service**
Mona-Oquirrh	UT Docket 09-035-54	Nov. 21, 2009	$ 450.00	5/31/2013	$ 364.00	5/31/2013
Sigurd-Red-Butte	UT Docket 12-035-97	Sept. 17, 2012	$ 380.00	6/30/2015	$ 357.80	6/30/2015

The Transmission Projects have the same project-management team, and the Company developed the budget and schedule in the same manner as these earlier projects. The Company's past experience substantially mitigates risks related to construction cost and schedule.

Q. How confident are you in the cost estimates for the Aeolus-to-Bridger/Anticline Line?

A. Very. The Company is confident that it will deliver the Aeolus-to-Bridger/Anticline Line at or below its cost estimates. Since starting the Energy Gateway program, which includes the Aeolus-to-Bridger/Anticline Line, the Company has used a Facilities Definition Document to clearly define and describe the required scope of the project to

all parties. The Facilities Definition Document is one of the foundations for the project successes described earlier in my testimony. This document was updated before developing the schedule and budgets that were included in the initial filing in this case. A clear definition of the project scope from the beginning of the project life-cycle brings an increased confidence in the accuracy of forecasts.

In addition, as an overall strategy of controlling contract cost and performance, the Company will secure fixed-price, fixed-performance-date contracts that will provide liquidated damages for late performance. The Company also uses project-management techniques to trend and forecast performance, including earned-value analysis, which provides an early notification of potential productivity concerns that can then be addressed before becoming a major issue. In fact, the Company anticipates executing contracts for the Aeolus-to-Bridger/Anticline Line (which is about 85 percent of the overall Transmission Projects' cost) in early 2018 that will effectively lock-in the cost for that line.

Q. Mr. Mullins also claims that the Company's estimated incremental O&M costs for the Transmission Projects is unsupported and the actual O&M may be much higher. (Mullins Direct, page 46, lines 13-18.) How do you respond to this claim?

A. The Company has a well-defined maintenance program that includes line and substation inspections, preventative maintenance, and corrective maintenance. The Company has extensive experience operating and maintaining both transmission and distribution assets. Based on the defined maintenance programs and the Company's experience with similar assets, the O&M costs assumed for this project are accurate.

Q. Mr. Mullins further claims the Company has a history of under-estimating transmission resource costs and cites the Populus-to-Terminal transmission line as an example. (Mullins Direct, page 5, lines 11-15.) Is Mr. Mullins's characterization of the cost estimates for the Populus-to-Terminal line correct?

A. No, Mr. Mullins's testimony on this point is very misleading. Based on Company filings in Idaho, Mr. Mullins testifies that the Populus-to-Terminal line was originally estimated to cost $78 million, but was actually constructed for $801 million, implying the Company's estimate was understated by more than $700 million. In fact, when the Company requested a certificate of public convenience and necessity ("CPCN") from the Idaho Public Utilities Commission for the Populus-to-Terminal line, its cost estimate was $750 million, which was within seven percent of the final costs.[3]

Q. What is the basis for Mr. Mullins's claim that the Populus-to-Terminal line was originally estimated to cost $78 million?

A. Mr. Mullins appears to have relied on a 2006 estimate provided by the Company in one of its commitments stemming from the merger with MidAmerican Energy Holding Company.[4] Mr. Mullins's testimony fails to note, however, that between the estimate included in the merger commitment and the actual construction of the Populus-to-Terminal line, conditions changed. Most notably, the 2006 merger commitment was a high-level estimate of the cost to construct a 300-MW transmission line, while

[3] *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*, IPUC Case No. PAC-E-08-03, Order No. 30657 at 2 (Oct. 10, 2008).

[4] *In the Matter of the Joint Application of MidAmerican Energy Holdings Company (MEHC) and PacifiCorp dba Utah Power & Light Company for an Order Authorizing MEHC to Acquire PacifiCorp*, IPUC Case No. PAC-E-05-08, Order No. 29998 at 6 (Mar. 14, 2006).

subsequent developments indicated that a much larger resource was required. The Populus-to-Terminal line ultimately provided 700 MW of immediate additional capacity and 1,400 MW of additional future capacity--a significant change from the size contemplated in the merger commitment. Mr. Mullins's comparison of the $78 million estimate in the merger commitment to the actual costs of the Populus-to-Terminal line is inapt.

Q. What about the risk of delay associated with obtaining the necessary permits and rights-of-way for the Transmission Projects?

A. The Company understands that the permitting process for transmission is complex, but it is already well on its way to securing all required permits. In my testimony regarding permit status, I note the Company is currently preparing applications for all of the major remaining permits. The schedule anticipates completing the permitting process by the end of 2018. To mitigate the risk of permitting delays, this schedule allows some delay without adversely impacting the overall construction schedule.

In addition, to further mitigate the risk of potential delays, the Company is actively engaging with stakeholders to inform them of the Transmission Projects and the applicable permit application process. The Company meets with the BLM on a regular basis to review project status, as well as planned or expected deliverables to the BLM and cooperating agencies in relevant areas such as Section 106 consultation and plan-of-development work. Similarly, the Company has met with the Wyoming ISC to review the application process, and the Company will soon engage with agencies supporting the Industrial Siting Permit to inform those agencies of the project details. Engaging with stakeholders increases the ability to understand local needs, identify

appropriate approaches and potential mitigation, and successfully complete the permit and approvals processes.

Although the Company does not intend to complete acquisition of rights-of-way until early 2019, it is confident this timing will not delay the Transmission Projects. The Company has engaged landowners on the projects since 2007 as part of its outreach for the overall Energy Gateway West project. During that time the Company learned a lot about the concerns of landowners and, where practical, has already addressed many of them.

In summer 2017, the Company renewed discussions with all landowners about the Transmission Projects. This effort identified, and continues to identify, additional concerns and questions the Company is committed to resolve to balance the needs of landowners with the project and its schedule. This renewed discussion will, through previous experience, resolve many issues and lead to successful conclusion of negotiations. Because any project will affect landowners in different ways, the effort and timeframe for negotiations will vary from landowner to landowner. When landowners are willing to actively engage in the process, timely resolution is almost always assured.

Q. How has the Company evaluated risks with the construction schedule?

A. Project risks related to the construction schedule fall broadly into three classifications: (1) restricted access due to environmental constraints; (2) weather restrictions; and (3) late commencement due to late receipt of all permits.

To mitigate the potential impacts due to environmental constraints, the Company considered its previous history constructing in areas with similar levels of

constraints and built the overall schedule based on this experience. From previous practical experience and the ongoing agency engagements described in my testimony, the Company understands that mitigation techniques, such as supervised or monitored access into environmentally restricted areas, is possible through negotiation and cooperation between parties. Additional mitigation plans, such as re-sequencing of work or schedule compression, have also been successfully employed on previous projects, with the contractor assuming the risk of occurrence for such items.

To mitigate the risk of constraints caused by weather, the schedule is set to minimize construction during the winter and perform additional work in the summer. In 2009, the Company engaged with several qualified and respected construction contractors to analyze the feasibility of the construction program. This informed the Company on the overall approach needed for the project and helped the Company develop the project schedule. In addition, the Company is currently negotiating contracts where the construction contractor will assume the risk for weather delays and allow for such delays in their schedule and the guaranteed completion dates in the contract.

Q. What are the primary risks and mitigation measures underway?

A. The primary risk in maintaining the critical-path construction schedule for the Transmission Projects is the on-going regulatory review and approval processes currently underway. Timely resource approval from the Commission is an important element of managing the project schedule. The Company needs to obtain CPCNs from the Wyoming Public Service Commission for the Transmission Projects, which are conditioned upon acquisition of all necessary rights-of-way, with sufficient time to

meet this condition. The Company must also obtain the outstanding siting permits by the end of 2018. If the Company does not receive conditional CPCNs in early 2018, or siting permits by the end of 2018, it must assess the viability of achieving a year-end 2020 online date before moving forward. To manage the risk of obtaining timely regulatory reviews and approvals, the Company will secure off-ramps in its EPC contracts, allowing assurance of regulatory approvals before significant capital commitments or outlays are made.

Q. Is the Company confident that it can manage the construction-schedule risk and deliver the Transmission Projects by 2020?

A. Yes. To manage construction-schedule risk, the Company will structure and manage the Transmission Projects on using firm, date-certain, fixed-price, turnkey contracts. Construction contractors and equipment suppliers will be held to key construction and delivery milestones and development of mitigation plans for compressed schedules, if required. The Company will establish completion dates in the construction contracts and backstop them with guarantees.

Q. Does the Company have experience building similar types of projects that require completion by a date-certain?

A. Yes. The Company has managed multiple major projects that required the work be completed by a date-certain, or similar circumstances where project completion was required to allow a project to tie into an existing system within a short planned-outage window or closely coordinated with delivery of transmission system network upgrades. Examples of these projects include: (1) Dunlap wind facility; (2) High Plains wind facility; (3) McFadden Ridge I wind facility; (4) Populus-to-Terminal 345-kV

transmission line; (5) Sigurd-to-Red-Butte transmission line; (6) Mona-to-Oquirrh transmission line; (7) Lake Side 2 combined-cycle natural-gas facility; (8) Jim Bridger Unit 3 and Jim Bridger Unit 4 selective catalytic reduction systems; (9) Naughton Unit 1 and Naughton Unit 2 flue gas desulfurization systems ("FDG"); (10) Hunter Unit 1, Hunter Unit 2, Huntington Unit 1, and Huntington Unit 2 pulse jet fabric filters ("PJFF"); (11) Wyodak PJFF; and (12) Dave Johnston Unit 3 and Dave Johnston Unit 4 PJFF and FGD systems.

Q. If the Transmission Projects are not fully in service by December 31, 2020, can the Wind Projects still qualify for PTCs?

A. Yes. Assuming the Transmission Projects are not completed by December 31, 2020, but otherwise have facilitated synchronization to the transmission grid and commissioning of individual wind turbines in accordance with Internal Revenue Service ("IRS") guidance, the Company would treat a completed and functional wind turbine as being placed in service regardless of any transmission constraints affecting a wind project. Ms. Nikki Kobliha addresses this issue in her rebuttal testimony.

Q. Mr. Davis claims that the Wind Projects may have to run at less than the full capacity to allow room on the transmission system for thermal resources that provide ancillary voltage and frequency service, and that this wind curtailment will potentially limit PTC production. (Davis Direct, lines 265 - 282.) Please respond.

A. It is anticipated that system resources will be operated in the most efficient manner feasible to maintain system integrity and reliability, which entails a combination of wind and thermal resources. While Mr. Davis' claim could technically be true at

times, particularly during a system event, this condition would be the exception rather than the rule. Frequency response can be appropriately managed with relatively small increases in thermal plant output. The Transmission Projects include plans for dynamic voltage support, and the Company will finalize the design of these facilities in summer 2018 now that the results of the 2017R RFP are available.

COSTS ASSOCIATED WITH THE ENERGY IMBALANCE MARKET

Q. Mr. Mullins claims the EIM will impose additional costs on the Wind Projects because they will be subject to uninstructed imbalance charges that were not included in the Company's economic analysis. (Mullins Direct, page 43, lines 14-17.) Is this true?

A. No. There is no basis to assume that uninstructed imbalance will result in a net cost and, in fact, the expectation is that over time there will be no net impact associated with uninstructed imbalance.

Q. What is uninstructed imbalance?

A. Uninstructed imbalance in the EIM is assessed when a unit does not follow its scheduled output in the five-minute market. For example, if the dispatch operating target for five minutes was 50 MW and the unit actually produced 55 MW, then there is an uninstructed imbalance of 5 MW. In this example, the 5 MW would be multiplied by the locational marginal price of the unit to determine the uninstructed imbalance assessment. Importantly, however, the assessment can be a charge or a credit because the locational marginal price for a particular unit can be positive or negative. All of the Company's generating units, as well as loads, have uninstructed imbalance. Mr.

Mullins is wrong to claim that uninstructed imbalance is somehow a negative outcome that will impose additional costs.

Also, as described by Mr. Teply in his rebuttal testimony, the wind forecasts that are provided to the Company's economic model are P50 forecasts, which assume a balanced outcome over periods of times, *i.e.*, there is a 50-percent probability that wind generation will be more than forecast and a 50-percent probability it will be below forecast. To impute a negative pricing outcome assumes that the times when the unit is under- or over-performing is somehow biased towards periods in which the dollar impact is less favorable, *e.g.*, always under-performs when prices are high or over-performs when prices are low (possibly negative). This would imply a bias in the outcome, which is an unreasonable assumption in a forecast for variable energy resources.

Finally, because the EIM is such a large, liquid market with renewable resource diversity, it further supports the assumption of a balanced price outcome when a resource or load deviates from a forecast.

Q. Mr. Mullins also claims the EIM operates only on the ability to transfer power on the firm rights of the Company, and does not allow transfers to occur on another utilities' transmission rights. (Mullins Direct, page 43, lines 5-7.) Is this true?

A. No. The opposite is true. The ability to use available transmission capability across the Western Interconnect of participating EIM entities and the California Independent System Operator Corporation ("CAISO") is the foundation of how benefits are realized in the EIM.

THIRD-PARTY TRANSMISSION REVENUE

Q. How will the costs of the Transmission Projects flow into the Company's transmission rates, and who will pay these rates?

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

Q. Mr. Mullins and Mr. Peaco claim the Company has not supported its assumption that 12 percent of the new investment in the Transmission Projects would be funded by OATT customers. (Mullins Direct, page 45, lines 3-8; Peaco Direct, lines 1023-1024.) Is this true?

A. No. As I explained above, FERC has approved the Company's current formula rate that will include the ATTR of the Transmission Projects once they are in-service, and the Company has gone through the annual update. The 12 percent figure represents the current level of ATRR funded by OATT customers.

Q. Does this conclude your supplemental direct and rebuttal testimony?

A. Yes.