ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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January 16, 2018

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-40
Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision

In accordance with the Scheduling Order and Notices of Technical Conference and Hearing in the above referenced docket issued by the Utah Public Service Commission on July 27, 2017, Rocky Mountain Power hereby submits for electronic filing its Supplemental Direct Testimony on RFP Results and Rebuttal Testimony.

As requested by the Commission, Rocky Mountain Power is also providing seven (7) printed copies of the filing via overnight delivery. Workpapers supporting this application will also be provided electronically.

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

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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

Joelle Steward
Vice President, Regulation

CERTIFICATE OF SERVICE

Docket No. 17-035-40

I hereby certify that on January 16, 2018, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

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Rocky Mountain Power
Docket No. 17-035-40
Witness: Cindy A. Crane

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct and Rebuttal Testimony of Cindy A. Crane

January 2018

Q. Are you the same Cindy A. Crane 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. I support the Company's request that the Public Service Commission of Utah ("Commission") approve its significant energy resource decision to construct and acquire new wind resources ("Wind Projects") and voluntary energy resource decision for construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects"). I provide overall policy support for the Company's supplemental testimony describing the results of the Company's 2017R request for proposals ("2017R RFP"). I also provide the policy rebuttal to the testimony filed by the Division of Public Utilities ("DPU"), Office of Consumer Services ("OCS"), the Utah Association of Energy Users ("UAE") and Utah Industrial Energy Consumers ("UIEC").

Q. Please summarize your testimony.

A. The results of the 2017R RFP make the Combined Projects an increasingly attractive resource opportunity for customers. The benefits are now greater and more certain, and the risks have decreased. The Combined Projects will provide substantial near-term and long-term customer benefits and represent the least-cost, least-risk strategy for meeting the needs of Utah customers. The Company's supplemental testimony demonstrates the Company has recognized and mitigated all potential risks and concerns.

In rebuttal testimony, the Company shows the Combined Projects are necessary to meet an identified resource need and present no more risk than typical utility investments. The Company will manage future potential risks either through the off-ramps built into the projects or by seeking additional direction from the Commission before or during project implementation.

SUPPLEMENTAL DIRECT TESTIMONY

Q. Based on the results of the 2017R RFP and the Company's updated analysis of benefits, costs, and risks, do the Combined Projects satisfy the public interest standard?

A. Yes. The Combined Projects are the least-cost, least-risk path available to serve the Company's customers by meeting both near-term and long-term needs for additional resources. Mr. Rick T. Link's supplemental direct testimony and updated economic analysis demonstrates increased customer benefits of $177 million in the medium case through 2050 (as compared to $137 million in the original filing), and a range of $311 million to $343 million in the medium case through 2036. As described further by Mr. Link, the treatment of production tax credits ("PTCs") in the system modeling scenarios extending out through 2036 has been changed to better reflect how the PTCs will flow through to customers, which makes the treatment consistent with the nominal revenue requirement results that extend out through 2050. Moreover, the updated economic analysis demonstrates the Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.

The fact that the Combined Projects will provide customer benefits significantly in excess of their costs is extraordinary. Customers will gain access to significant new wind and transmission resources, with important environmental and system reliability attributes, and still enjoy lower overall costs as a result of this investment.

Q. What evidence is the Company including in the supplemental direct filing to demonstrate that the Combined Projects are in the public interest?

A. In addition to updating the Company's economic analysis, Mr. Link provides information on the 2017R RFP, which generated robust and competitive responses from market participants. Mr. Chad A. Teply describes the four Wind Projects, totaling 1,170 megawatts ("MW"), which were selected for the final shortlist through this solicitation process: TB Flats I and II; McFadden Ridge II; Cedar Springs; and Uinta. He also details the Company's extensive and ongoing efforts to minimize technical and construction risk associated with the Wind Projects. Mr. Rick A. Vail updates the status of the development of the Aeolus-to-Bridger/Anticline 500 kV transmission line, and confirms that the costs of the line (which represents roughly 85 percent of the costs of the Transmission Projects) remain unchanged. Mr. Vail also updates the network upgrade and interconnection facilities based on the outcome of the 2017R RFP. Ms. Nikki L. Kobliha describes the outcome of federal tax reform, and discusses how tax-related risks have been resolved. Together, this evidence shows that the Combined Projects satisfy the Commission's public interest standard.

Q. Is the Company's supplemental direct filing consistent with the procedure proposed in the Company's request for resource approval and in the schedule approved by the Commission?

A. Yes. The supplemental direct filing allows the Company to update its pending request for resource approval to reflect the results of the 2017R RFP. This process allows for full review of the Combined Projects, including review of the results of the 2017R RFP, by April 2018, a schedule necessary to preserve for customers the time-sensitive resource opportunity presented by the availability of PTCs for the Wind Projects.

Q. Based on the results of the 2017R RFP, what modification is the Company making to its request for significant energy resource approval?

A. The Company's original request sought approval for the construction or acquisition of four new wind resources--three 250 MW facilities (Ekola Flats and TB Flats I and II), and a fourth 100 MW facility (McFadden Ridge II)—for a total of 860 MW. These were the benchmark facilities for the 2017R RFP.

Based on the results of the 2017R RFP, the Company is now seeking approval of the significant energy resource decision to construct or procure four new Wyoming wind projects with a total capacity of 1,170 MW, including three of the benchmark facilities (TB Flats I and II, now combined as a single project, and McFadden Ridge II), and two new facilities (Cedar Springs and Uinta). Uinta is a build-transfer agreement (“BTA”), totaling 161 MW, Cedar Springs is one-half BTA and one-half power purchase agreement (“PPA”), for a total of 400 MW, and TB Flats I and II and McFadden Ridge II are Company-built facilities, totaling 500 MW and 109 MW, respectively. Thus, the 2017R RFP will result in 970 MW of Company-owned facilities, and a 200 MW PPA.

Q. Has any aspect of the Aeolus-to-Bridger/Anticline transmission line changed as a result of the 2017R RFP?

A. No. The proposed route and facilities required for the construction of the Aeolus-to-

Bridger/Anticline line have not changed. The only change related to the line is the fact that the costs are now more certain.

Q. Are there any modifications to the network upgrades included in the Company's initial filing?

A. Yes, in addition to the network upgrades included in the Company's initial filing, there are additional network upgrades required to interconnect McFadden Ridge II, Cedar Springs, and Uinta. Mr. Vail provides a detailed description of these network upgrades in his supplemental direct testimony.

Q. The Company's original filing contained a capital cost estimate of approximately $2 billion for the Combined Projects. With additional wind resources and network upgrades, have the total costs of the Combined Projects changed?

A. No. The overall capital cost of the Combined Projects remains the same–approximately $2 billion. This is true even though the supplemental filing reflects 970 MW of Company-owned resources, 110 MW more than the original filing. As Mr. Link explains, the per-unit capital cost for the benchmark wind projects in the initial filing was $1,590/kW. As a result of the 2017R RFP, the costs of the Company-owned wind projects decreased by roughly 17 percent to $1,320/kW.

Q. Please explain how the Company was able to acquire significant additional wind resources for approximately the same overall cost.

A. The robust response to the 2017R RFP process reduced costs and enabled the Company to select the most optimal projects to maximize customer benefits, as described by Mr. Link. The Company received 49 bid alternatives for 13 wind projects in Wyoming, totaling 4,624 MW. The Company also received 15 bid alternatives for six non-

Wyoming wind projects, totaling 595 MW.

Q. Has the Company further mitigated customer risks associated with the Combined Projects?

A. Yes. Three key risks associated with the Combined Projects have been either entirely or substantially mitigated. First, as described by Ms. Kobliha, the uncertainty surrounding federal tax reform has been resolved. The economic analysis in Mr. Link's testimony accounts for the lower federal corporate income tax rate and demonstrates that the overall cost reduction resulting from the 2017R RFP more than offsets the impact of the lower tax rate. Moreover, the policy discussions surrounding tax reform indicate that it is highly unlikely that PTCs will be extended beyond 2020—meaning that the time to act is now or customers will lose out on substantial savings.

Second, the Company has addressed the price risk associated with long-term forecasting by demonstrating the Combined Projects are expected to provide robust customer benefits under all scenarios in the economic analysis through 2036, including the scenario with low natural-gas prices and a zero carbon-dioxide price.

Third, the costs and schedule of the Combined Projects are now more certain. Based on the results of the 2017R RFP and the continued development efforts related to the Transmission Projects, the Company is confident that it can deliver the expected customer benefits.

Q. Based on the Company's updated economic analysis, has the Company updated its forecast of the near-term rate impact to Utah customers?

A. Yes. As explained in the testimony of Ms. Steward, the first year revenue requirement of the Combined Projects is reduced 20 percent from the initial filing. The near-term rate impact of the Combined Projects is now less than 1.6 percent in 2021, the first full year of operation.

REBUTTAL TESTIMONY

Q. Parties question whether there is a need for the Aeolus-to-Bridger/Anticline transmission line independent of the Wind Projects. How do you respond to this concern?

A. There is an independent need for the Aeolus-to-Bridger/Anticline line even if the new Wind Projects are not constructed because the line will improve system performance and reliability and directly serve customers. As explained by Mr. Vail, even without the Wind Projects, the Company plans to construct the Aeolus-to-Bridger/Anticline line in 2024 because it is an integral component of both the Company's and the region's long-term transmission plan. Thus, the issue is not *if* the Aeolus-to-Bridger/Anticline line will be constructed, but *when*. Under the proposal here, the Company can construct the line by 2020 and provide all-in net benefits to customers, rather than waiting until 2024 when PTC-eligible wind is no longer available to subsidize the line.

The results of the 2017R RFP provide further evidence of high demand for the Aeolus-to-Bridger/Anticline line. Over 4,500 MW of new high-capacity-factor wind projects that bid into the 2017R RFP are behind the existing constraint, showing the need for new transmission capacity in southeast Wyoming to give these potential resources a chance to move forward. The construction of the Aeolus-to-Bridger/Anticline line is a critical step to allow high-capacity-factor wind resource development in this area.

Q. Parties argue that the forecasted benefits of the Combined Projects are speculative and, even in the best scenarios, are insufficient in comparison to the overall project costs. Do you agree?

A. No. The parties' criticisms are largely premised on their claim that the Combined Projects are discretionary and therefore subject to a higher standard for approval than a project intended to meet customer need. However, as described by Mr. Link, the Combined Projects are not merely an economic opportunity. Instead, the projects are part of the Company's least-cost, least-risk plan for meeting resource needs. The innovation in the Company's plan is the opportunity to bring near-term and long-term benefits—in system reliability and flexibility as well as financial benefits—to our customers by capitalizing on the continued (but short-lived) availability of federal PTCs to acquire new resources without substantial increases in rates.

Q. The parties argue there is a significant risk that benefits will not materialize as claimed by the Company and the Combined Projects may prove uneconomic in the long run for reasons beyond the Company's control. Do you agree?

A. No, I do not agree. Mr. Link's sensitivity modeling is designed to capture a wide range of conditions and circumstances that could impact the economics of the Combined Projects. The Company's economic analysis shows that the Combined Projects deliver substantial benefits under all sensitivities in the analysis through 2036.

While all resource decisions inherently include some risk, the Company has demonstrated a high likelihood that the Combined Projects will be beneficial to customers. Moreover, the risks associated with the Combined Projects are typical of all utility investments and, as Mr. Link explains in his rebuttal testimony, there are risks associated with foregoing the time-limited opportunity to secure PTC-eligible resources.

Q. If circumstances arise that make the Combined Projects uneconomic, has the Company structured off-ramps to allow it to stop project development?

A. Yes. The Company recognizes that changing circumstances require that the Company continually reassess the project economics and establish off-ramps before development occurs. As addressed by Mr. Vail, the Company will soon negotiate and finalize most of the construction contracts for the Transmission Projects, which will lock in pricing. The Company will also prudently negotiate precautionary off-ramps in the contracts to allow it to exit the Transmission Projects if they become uneconomic. As addressed by Mr. Teply, the timing and terms of the execution of the contracts necessary to procure or construct the Wind Projects will also provide flexibility to allow the Company to reassess project economics, if necessary, before executing the contracts.

Q. How will the Company respond if it receives approval of the Combined Projects in this docket and a subsequent event occurs that adversely affects the economics of the Combined Projects during implementation?

A. If an adverse change of circumstances materially affects the Combined Projects' economics, the Company will seek additional Commission review of whether to proceed with implementation, as allowed under Utah Code Ann. § 54-17-404.[1]

[1] Utah Code Ann. §54-17-404(1)(a) ("In the event of a change in circumstances or projected costs, an energy utility may seek a commission review and determination of whether the energy utility should proceed with the implementation of an approved resource decision.").

Q. If significant portions of the Wind Projects do not ultimately qualify for PTCs due to delays or because they incur unanticipated cost increases within the Company's control, is the Company prepared to bear those risks?

A. Yes. The Company will take every precaution to ensure that the Wind Projects meet the requirements and timelines to qualify for full PTC benefits. While we do not believe it is appropriate for the Company to absorb risks beyond its control, we are prepared to accept risks associated with our performance. We are confident that we will complete the Combined Projects before the 2020 deadline.

Q. What happens if the actual costs of the Combined Projects exceed the estimated costs included in the supplemental filing?

A. As discussed by Ms. Steward, the Company agrees to a soft cap based on the cost estimate included in the Company's supplemental filing. If the actual costs are greater than the final estimate here, the Company agrees that it must demonstrate the prudence of the additional costs in a later ratemaking proceeding.

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

A. Yes.

Rocky Mountain Power
Docket No. 17-035-40
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct and Rebuttal Testimony of Chad A. Teply

January 2018

Q. Are you the same Chad A. Teply who submitted direct testimony in this proceeding on behalf of Rocky Mountain Power ("the Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. In my supplemental direct testimony, I reflect the results of the Company's 2017R request for proposals ("2017R RFP"), by updating my direct testimony supporting the Company's proposal to construct or procure new wind resources ("Wind Projects") and to construct the Aeolus-to-Bridger/Anticline transmission line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects"). I describe the four new wind facilities totaling 1,170 megawatts ("MW") selected as final shortlist resources in the 2017R RFP, and explain how those resources compare to the original proxy benchmark resources incorporated into my direct testimony. I also provide the information required by Public Service Commission of Utah ("Commission") Rule R746-430-2(1)(a), (b), (e) and (f) for the Wind Projects and for the associated facilities necessary to interconnect the Wind Projects. The other requirements under Rule 746-430-2(1) are addressed in the testimony of the other witnesses supporting the Application.

In my rebuttal testimony, I respond to the testimony of the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni Zenger and Mr. Daniel Peaco, and Office of Consumer Services ("OCS") witness Mr. Philip Hayet.

Q. What are the key issues you address in your rebuttal testimony?

A. The key issues include:

1. Development and procurement of the Wind Projects is on schedule, so the Company can timely deliver them and address the risks identified in the parties' testimony with risk-mitigation measures that advance the public interest.
2. The implementation schedules for the Combined Projects continue to provide reasonable timelines to assess project risks, incorporate the assessments into decision-making, and allow for changes in project direction in response to changing circumstances (*i.e.*, off-ramps).

Q. Please summarize your testimony.

A. The Company recognizes the unique circumstances resulting from the time-sensitivity of the resource opportunity. The Company has addressed these circumstances with a project schedule that permits the Company to comprehensively assess and confirm the economic benefits of the Combined Projects as development progresses and mitigate the risks inherent in projects of this scope.

The Company preliminarily announced the final shortlist from the 2017R RFP on January 8, 2018. The Company successfully engaged the competitive market, and the RFP results increase the benefits of the Combined Projects to customers. The Company is on track to successfully deliver the Combined Projects by year-end 2020 through timely development, procurement, and implementation. All of the steps taken by the Company ensure that the Wind Projects will qualify for production tax credits ("PTCs").

The Company's extensive experience successfully developing comparable projects supports its firm belief that it can deliver the Combined Projects and provide substantial customer benefits. If changing circumstances adversely impact the economics of the Combined Projects, the Company has established reasonable timelines to assess project risks, incorporate the assessments into decision-making, and allow for changes in project direction in response to changing circumstances (*i.e.*, off-ramps). The Combined Projects are in the public interest and provide substantial benefits to customers.

SUPPLEMENTAL DIRECT TESTIMONY

Q. Please describe the Wind Projects selected to the 2017R RFP final shortlist.

A. The Wind Projects selected to the 2017R RFP final shortlist are four facilities in Wyoming totaling approximately 1,170 MW:

1. McFadden Ridge II – 109 MW Company benchmark;
2. TB Flats I and II (combined into single project) – 500 MW Company benchmark;
3. Cedar Springs – 400 MW third-party build-transfer and power purchase agreement; and
4. Uinta – 161 MW third-party build-transfer.

Q. How do these projects relate to the benchmark projects included in the Application?

A. In its Application, the Company provided detailed information on four proxy benchmark wind facilities and committed to providing updated information regarding the Wind Projects ultimately selected in the 2017R RFP. The Company's McFadden Ridge II and TB Flats I and II benchmarks were selected to the final shortlist. The

Company's fourth benchmark wind facility, Ekola, was not selected to the 2017R RFP final shortlist.

Q. Please describe the McFadden Ridge II project.

A. McFadden Ridge II is a nominal 109 MW wind facility located in Carbon and Albany counties, Wyoming, which the Company is currently developing on a Company-controlled site. McFadden Ridge II is expected to have approximately 44 2.3-MW-to-2.5-MW wind turbine generators. The facility will consist of an electrical collection system, a 34.5-kilovolt ("kV") to 230-kV collector substation, 230-kV breakers, a 230-kV tie-line between the wind project and the point-of-interconnection substation, meteorological towers, access roads, and required communication and control facilities (*e.g.*, metering, hardware, software, and associated communication circuits and other equipment).

The McFadden Ridge II project selected to the shortlist is substantively identical to the project described in the Company's direct testimony.

Q. Please describe the TB Flats I and II projects.

A. TB Flats I and II is a nominal 500 MW wind facility located primarily in Carbon County, Wyoming, although some facilities may be sited in Albany County as well. We expect TB Flats I and II to have approximately 134 2.0-MW-to-4.2-MW wind turbine generators and similar project infrastructure as described for McFadden Ridge II, with the addition of an operations and maintenance ("O&M") building.

The TB Flats I and II project, as selected to the 2017R RFP final shortlist, was submitted as a single Company benchmark project alternative to benefit from economies of scale and is no longer presented as two stand-alone projects of 250 MW for TB Flats I and 250 MW for TB Flats II projects as originally described in the Application.

The TB Flats I and II project is substantively identical to the TB Flats I and TB Flats II projects described in the Company's direct testimony.

Q. Please describe the Cedar Springs project.

A. Cedar Springs is a nominal 400 MW wind facility located in Converse County, Wyoming, and is being developed by a third-party. We expect the project to consist of approximately 161 2.3-MW-to-2.5-MW wind turbine generators and similar project infrastructure as described for McFadden Ridge II, with the addition of an O&M building. The Cedar Springs project, as proposed, will be procured as 50 percent build-transfer and 50 percent power purchase agreement.

Q. Please describe the Uinta project.

A. Uinta is a nominal 161 MW wind facility located in Uinta County, Wyoming. The Uinta project is being developed and delivered by a third-party under a build-transfer agreement. We expect the project to consist of approximately 47 2.3-MW-to-3.6-MW wind turbine generators and similar project infrastructure as described for McFadden Ridge II, with the addition of an O&M building.

Q. What are the total costs for the Wind Projects?

A. The proposed Wind Projects are estimated to cost approximately $1.30 billion, recognizing the split procurement attributes of the Cedar Springs facility. This amount is lower than the cost estimate for the initial benchmark projects included in the Application, even though the Wind Projects selected to the 2017R RFP final shortlist provide additional capacity. The overall costs of the Combined Projects reflected in the

Company’s supplemental direct testimony are consistent with the costs included in the Application.

Q. Do all four Wind Projects rely on the Transmission Projects for interconnection?

A. No. McFadden Ridge II, TB Flats I and II, and Cedar Springs, which total 1,009 MW, rely on the construction of the Transmission Projects, which will relieve existing congestion and allow interconnection of those Wind Projects. Uinta, which has a nominal capacity of 161 MW, will interconnect to the Company’s Wyoming transmission system in southwest Wyoming and is not reliant on the Transmission Projects for interconnection and delivery. In total, the benefits generated by the Wind Projects' zero-fuel-cost generation, which lowers net power costs and provides 10 years of PTCs, continue to support cost-effective development of the Transmission Projects.

Q. Did the 2017R RFP consider the recently passed federal tax legislation and any potential impacts on wind project proposals?

A. Yes. As discussed in detail in Mr. Rick T. Link’s testimony, the 2017R RFP process was adjusted to allow proposals to be updated to reflect any impacts to proposal pricing, or project viability, before determination of the final shortlist.

Q. Has recently passed federal tax legislation resulted in a change to the time-sensitive nature of the Combined Projects?

A. No. The time-sensitive nature of the Combined Projects remains and is primarily driven by the pending phase-out of PTCs for new wind resources. As Company witness Ms. Nikki L. Kobliha explains, the recently passed federal tax legislation did not modify the PTC provisions of the tax code.

Q. To receive 100 percent of safe-harbor PTCs, must wind turbine generators still be placed in service by the end of calendar year 2020?

A. Yes. To receive 100 percent of safe-harbor PTCs, wind turbine generators in new facilities that began construction before January 1, 2017, through purchase of safe-harbor equipment, must be reviewed, approved, implemented, and placed in-service by year-end 2020 to be eligible for the full PTC. The Company's implementation schedule for the Combined Projects is designed to meet these criteria and provide customers the economic benefit of 100 percent of the PTCs.

Q. Do the Wind Projects selected to the 2017R RFP final shortlist meet the Internal Revenue Service's ("IRS") start-of-construction criteria?

A. Yes. The Company confirmed through its due diligence efforts that each of the Wind Projects selected to the 2017R RFP final shortlist have acquired, or have the rights to, sufficient wind turbine generator equipment and other facility-specific components before December 31, 2016, to meet the start-of-construction definition for tax purposes. These transactions satisfy the safe-harbor requirements under the PTC guidance issued by the IRS. More specifically, the Company has confirmed 2016 safe-harbor purchases of wind turbine generator equipment for each of the 2017R RFP final shortlist Wind Projects with the respective project developers. Each of the shortlisted 2017R RFP project developers has provided the appropriate evidence of the safe-harbor purchases that will be applied to each of the respective Wind Projects.

Q. How does the Company plan to continue to procure the Wind Projects selected to the 2017R RFP shortlist?

A. With the final shortlist determined, the Company will continue to engage the shortlisted counterparties in negotiations to finalize terms and conditions, with a target for execution of definitive agreements by April 16, 2018. The final shortlist Wind Projects include a combination of Company benchmark resources, facilities that have been selected instead of one or more of the Company benchmark resources, and facilities in addition to the Company benchmark resources. These Wind Projects have been assessed as equal-to or better-than the Company benchmark resources included in the Application. In each case, the individual Wind Projects' developer has submitted its proposed commercial structure for construction and procurement of the resource within the guidelines of the 2017R RFP.

Q. Please provide an updated timeline of key decision points, regulatory outcomes, and project development activities.

A. The following timeline provides an overview of the key events that have already occurred, and the events that will occur as the currently anticipated resource procurement and development efforts continue.

Energy Vision 2020 New Wind and Transmission Timeline

2017	**Apr, 4, 2017—PacifiCorp 2017 Integrated Resource Plan ("IRP") filing** **Jun. 30, 2017—Idaho CPCN filing** **Jun. 30, 2017—Wyoming CPCN filing** **Jun. 30, 2017—Utah Resource Decision filing** **Sept. 27, 2017—PacifiCorp 2017R RFP issued to market** **Nov. 17, 2017—PacifiCorp 2017R RFP initial shortlist determination** **Nov. 22, 2017—PacifiCorp 2017R RFP initial shortlist price updates from market** **Dec. 11, 2017—Oregon Commission action on 2017 IRP action items** **Dec. 2017—U.S. Tax Code legislation passed**

2018	**Jan. 8, 2018—PacifiCorp 2017R RFP final shortlist determination** **Jan. 16, 2018—Idaho CPCN supplemental filing** **Jan. 16, 2018—Wyoming CPCN supplemental filing** **Jan. 16, 2018—Utah Resource Decision supplemental filing** **Feb. 22–28, 2018—Wyoming CPCN public hearing** **Mar. 6–9, 2018—Utah Resource Decision public hearing** **Mar. 12–15, 2018—Idaho CPCN public hearing** **Mar. 9, 2018—Wyoming legislative session ends (budget session)** **Apr. 6, 2018—Idaho CPCN Commission Order** **Apr. 6, 2018—Utah Resource Decision Commission Order** **Apr. 30, 2018—Wyoming CPCN Commission Order (conditioned upon rights-of-way (“ROW”) acquisition)** **Apr. 16, 2018—Executable Wind Projects Agreements Finalized** **May 1, 2018—Begin Transmission Projects ROW acquisition** **May 31, 2018—Wind Projects Limited Notice to Proceed (“LNTP”)** **Jun. 30, 2018—USFWS Eagle Take Permit first-year data collection complete (benchmarks)** **Nov. 30, 2018—Transmission Projects EPC Contract LNTP (500 kV)** **Dec. 31, 2018—Wyoming Industrial Siting Council permits received, New Wind (benchmarks)** **Dec. 31, 2018—Wyoming Industrial Siting Council permit received, Transmission**

2019	**Jan. 1, 2019—Complete Transmission Projects ROW acquisition (anticipated)** **Jan. 1, 2019—Wyoming CPCN issued (transmission ROW acquired; anticipated)** **Mar. 31, 2019—Wyoming legislative session ends (full session; approximate date)** **Apr. 1, 2019—Transmission EPC Contract Full Notice to Proceed (“FNTP”) (500 kV)** **Apr. 1, 2019—Wind Projects FNTP** **Apr. 1, 2019—Wind Projects Turbine Supply Agreement release (benchmark)** **Jun. 30, 2019—USFWS Eagle Take Permit second-year data collection complete (benchmarks)** **Sept. 30, 2019—Submit voluntary USFWS Eagle Take Permit application (benchmarks)**
2020	**Mar. 15, 2020—Wyoming legislative session ends (budget session; approximate date)** **Dec. 31, 2020—Receive voluntary Eagle Take Permit (if issued by USFWS)** **Dec. 31, 2020—New Wind and Transmission Projects in-service**

Q. Is the Company currently on track to meet this development schedule and complete the Combined Projects by the end of 2020?

A. Yes.

Q. Does the timeline above provide off-ramps to allow the Company to revise, or potentially terminate, development efforts in response to changes in federal income tax policy, project permitting, or other risks associated with the Combined Projects?

A. Yes. In particular, the Company has incorporated the changes to the federal corporate income tax code into the economic analysis included in Mr. Link’s supplemental direct testimony. Thus, the risk associated with changes in federal tax rates have been resolved.

To provide further risk mitigation, the timeline for developing and implementing the Combined Projects contemplates offering limited notices to proceed ("LNTP") to key engineering, procurement, and construction ("EPC") contractors and build-transfer project counterparties associated with the projects after obtaining the Certificate of Public Convenience and Necessity ("CPCN") from the Wyoming Public Service Commission. The LNTP will facilitate EPC contractor support of the Wyoming Industrial Siting Council permit review and hearing processes, as well as initiation of certain engineering and pre-procurement activities. The LNTP concept incorporated into these key contracts will limit cost commitments while allowing critical parallel path project development activities and approvals to progress.

The project timeline also incorporates off-ramps to ensure the transmission rights-of-way ("ROW") acquisition effort is complete and the final CPCNs are obtained before release of full notice to proceed ("FNTP") to EPC contractors and build-transfer counterparties for the Combined Projects. Under the terms of the major contracts for the Combined Projects that will be awarded by the Company, FNTP allows the EPC contractors to proceed with their major equipment purchases, site mobilization, and subcontract awards that also entail the associated cost commitments for those activities. Recognizing that a successful and timely ROW acquisition process is fundamental to the overall success of the project, negotiation of the FNTP terms described above with major contractors and counterparties provides another layer of risk mitigation that the Company has incorporated into its planning.

CONTINUED DEVELOPMENT, NEGOTIATIONS, AND IMPLEMENTATION

Q. What is the current status of development for each of the Wind Projects?

A. As part of the 2017R RFP process, the Wind Projects have undergone preliminary vetting for interconnection status, wind resource performance, PTC eligibility, permitting status, conformance to specifications, constructability, and equipment supply. Going forward, the Company's resource development team will engage shortlisted project counterparties in detailed commercial negotiations of scope, schedule, cost, and terms within the construct of the 2017R RFP, and otherwise continue with established development plans and activities for the Wind Projects.

Q. Will the Company develop additional information for the Wind Projects?

A. Yes. If material changes in circumstances or new information on the Wind Projects becomes available during the detailed negotiations, ongoing development, and project implementation activities, the Company will assess the information to ensure the Company delivers the most competitive Wind Projects for customers. The Company will communicate any material changes in circumstances, as discussed in the supplemental direct and rebuttal testimony of Company witnesses Ms. Cindy A. Crane and Ms. Joelle R. Steward.

Q. Will the Company provide additional landowner notifications now that the 2017R RFP final shortlist has been identified?

A. Yes. To ensure compliance with the Wyoming statute on landowner notifications associated with CPCN applications for wind and transmission facilities, the Company updated landowner information for parcels within 2,000 feet of any 230 kV transmission lines related to the Wind Projects and will work with the Wyoming Public

Service Commission to notify any landowners who were not previously included in the landowner notifications related to the Transmission Projects.

Q. Are applications with the Wyoming Industrial Siting Council ("ISC") for the Wind Projects being prepared?

A. Yes. The Company's McFadden Ridge II benchmark project scope was included in a previous permitting process before the ISC, which was approved. The ISC Permit Applications for the TB Flats I and II, Cedar Springs, and Uinta projects are being developed and will be filed in accordance with the individual project development and implementation schedules to support year-end 2020 in-service dates now that those projects have been selected to the 2017R RFP final shortlist. Based upon a review of the shortlisted project schedules, the Company expects the ISC review processes and hearings for the TB Flats I and II, Cedar Springs, and Uinta projects will proceed through April 2019, subject to updates identified during detailed negotiation of project contracts, schedules, and implementation plans with each of the shortlisted Wind Projects counterparties. The ISC is required to hold a hearing within ninety days of each application under W.S. § 35-12-109.

Q. Does the Company anticipate landowner participation in the ISC proceedings associated with the Wind Projects?

A. Yes. Based upon past experience in siting wind resources in Wyoming, as well as the landowner intervener interests in this docket, the Company anticipates robust participation of landowners in the ISC proceedings for each of the Wind Projects to ensure that all issues and concerns within the scope of the ISC permit process are fully vetted.

Q. Has the Company performed preliminary evaluations of the wind potential at each Wind Project site?

A. Yes. Studies for each of the Wind Projects were completed by the individual project developers. The Company also validated wind potential with a third-party wind resource evaluation firm as part of the 2017R RFP process. Wind assessments for each of the Wind Projects indicate that the sites have favorable wind regimes suitable for high performance wind resources. In particular, the Company previously provided testimony in this docket regarding the wind resources and the anticipated capacity factors expected to be produced by the Company's project layouts for the McFadden Ridge II and TB Flats I and II wind projects. The third-party developers of the Cedar Springs and Uinta Wind Projects provided similar assessments of the wind resources and expected capacity factors for their projects, which is included in the exhibits for each project attached to my testimony.

The 2017R RFP evaluation team also reviewed the wind resource assessments for each project and independently determined whether the wind data for each project supported the proposed capacity factors or whether adjustments to the proposed capacity factor for a project were warranted. Mr. Link provides additional testimony regarding the results of the 2017R RFP team's independent review in his supplemental direct testimony.

Q. Has each Wind Project developer determined who will be responsible for construction of each project?

A. Not yet. Each of the Wind Project developers has indicated its intent to issue competitive procurement requests for proposals to obtain firm-fixed pricing to engineer, procure, construct and commission each wind facility now that they have been added to the 2017R RFP final shortlist. For the McFadden Ridge II and TB Flats I and II projects, the Company is negotiating with shortlisted EPC contractors that submitted formal proposals in 2017.

Q. Has each Wind Project developer determined who will supply the wind turbine generators for each Wind Project?

A. Not entirely. As discussed above, each of the Wind Project developers has acquired or has rights to acquire safe-harbor wind turbine generator equipment and other project-specific components, which it proposes to use at the Wind Projects as required to meet the IRS's start-of-construction criteria for PTC eligibility. Each of the Wind Project developers also indicated its intent to finalize procurement of follow-on wind turbine generator equipment through competitive procurement requests for proposals or under existing master supply agreements, and identified its intended equipment suppliers, models, and configurations in its 2017R RFP submittals.

Q. How did the Company generate the cost information for construction, operation, and maintenance of the individual Wind Projects through their useful lives?

A. As further discussed in Mr. Link's testimony, the Company prepared its capital cost estimates for the Wind Projects using information from a variety of sources.

For its McFadden Ridge II and TB Flats I and II benchmark Wind Projects, the Company obtained wind turbine costs from competitive procurement processes that were held in 2016 to procure the Company's safe-harbor wind turbine generator equipment and in 2017 for follow-on wind turbine generator equipment. The Company also obtained balance of plant engineering, procurement, construction, and commissioning costs from a competitive procurement process that was held in 2017 to support final submittals in the 2017R RFP process. Transmission interconnection costs were estimated using comparable wind facility transmission studies and prior project experience, and internal project development, management and permitting costs were estimated based upon the Company's experience with construction of past wind facilities and other recent generation resource additions. The Company applied contingencies in various cost categories to account for project uncertainties given the current stage of development of the project. O&M cost estimates were developed based upon the Company's experience with wind resource O&M budgets and third-party contracts for the Company's existing wind facilities. Ongoing capital costs were estimated based upon the Company's experience and indicative costs provided by wind turbine generator suppliers for critical capital components.

For the third-party developed Wind Projects, the Company received competitive market proposals for a combination of build-transfer projects and power purchase agreements within the guidelines provided in the 2017R RFP. All bid proposals received through that process require a bid validity date through April 16, 2018, and final shortlist bidders provided a letter signed by an officer that commits to the requirements of the 2017R RFP. Transmission interconnection costs for the individual projects were informed by transmission system impact studies, and internal project development, management, and permitting costs were estimated based upon the developers' experience with development and construction of past wind facilities. O&M cost estimates were developed based upon the Company's experience with wind resource O&M budgets and third-party contracts for the Company's existing wind facilities. Ongoing capital costs were estimated based upon the Company's experience and indicative costs provided by wind turbine generator suppliers for critical capital components.

Q. Will the Company and third-party developers collaborate with the Wyoming Game and Fish Department, the U.S. Fish and Wildlife Service, and other environmental agencies to develop and implement the Wind Projects?

A. Yes. The Company and the third-party project developers have initiated discussions with the Wyoming Game and Fish Department and the U.S. Fish and Wildlife Service regarding developing and implementing the Wind Projects. The Company and the third-party project developers have also begun pre-construction usage surveys for various avian, bat, and wildlife species using recommendations from applicable state and federal guideline documents, including the 2012 Land Based Wind Energy Guidelines. The Company and third-party project developers will coordinate with county, state, and federal agencies that have jurisdiction over development, permitting, and operations to ensure appropriate environmental and safety measures are implemented throughout the life of the Wind Projects. The Company is committed to establishing development and implementation schedules and protocols that recognize the potential environmental impacts of the Wind Projects and strive to mitigate negative impacts.

Q. Will the Wind Projects' wind turbine generators or associated infrastructure be built in Wyoming's Greater Sage Grouse Core area?

A. No. The Wind Projects' wind turbine generators and associated infrastructure, including the associated generation interconnection tie-lines, will not be located within the current boundaries of Wyoming's Greater Sage Grouse Core area.

Q. How will potential visual and lighting impacts from the Wind Projects be addressed?

A. State and county permitting regulations contain requirements that recognize and address potential visual and lighting impacts. The Company and third-party developers will incorporate those applicable measures into the siting, construction, and operations of the Wind Projects as part of the permitting process. Such measures may include: down shielded lighting on project infrastructure; Federal Aviation Administration approved/recommended turbine lighting protocols; active aviation light management; and use of approved paint colors for turbines.

Q. When will construction of the Wind Projects begin and end?

A. As described in detail in the exhibits attached to my testimony, site construction of the Wind Projects will begin as soon as the second quarter of 2019. The Company and the third-party developers will not begin construction, however, until all of the necessary regulatory approvals and applicable permits and authorizations from other local, state, tribal or federal governmental agencies that have jurisdiction over the construction or operation of the Wind Projects have been received, including approval from the Wyoming ISC to ensure that the projects ultimately selected are in the best interest of customers. The Company anticipates that substantial completion for the Wind Projects, under normal construction circumstances, weather conditions, labor availability and materials delivery, will be achieved by November 15, 2020, or as otherwise updated during detailed negotiation of project contracts, schedules, and implementation plans with each of the shortlisted Wind Projects counterparties.

Q. What is the expected operational life of the Wind Projects?

A. The anticipated operational life of the Wind Projects has been assessed at 30 years for the purposes of the Application and this supplemental filing, which aligns with the Company's currently approved depreciable life for wind resources. The operational life may be reviewed and extended based on advances in turbine technologies or improvements in maintenance processes (or both) through the course of the Company's regular depreciation studies and filings.

Q. Will the Wind Projects be decommissioned or repowered at the end of their operational life?

A. The Company may dismantle and reclaim the Wind Projects delivered under a build-transfer agreement at the end of their operational life based upon the requirements of the operating permit. Typically, county and state agencies identify the decommissioning requirements during the permitting process, including expected reclamation efforts and overall decommissioning costs and security requirements. The Company may also consider replacing or upgrading the existing infrastructure at the end of the operational life if conditions (*i.e.*, economics, permitting, customer load needs, etc.) are conducive to reinvestment in the Wind Projects.

REQUIREMENTS OF COMMISSION RULE 746-430-2(1)

Q. Please summarize how the Company's Application meets the requirements for approval of a significant energy resource.

A. Commission Rule 746-430-2(1) describes what must be included in an application for approval of a significant energy resource. As such, I have incorporated exhibits to my testimony that provide information for the Wind Projects pertaining to R746-430-

2(1)(a), (b), (e) and (f) requirements. The other requirements under Rule 746-430-2(1) are addressed in the testimony of the other witnesses supporting the Application.

Q. Please describe your exhibits for the nominal 400 MW Cedar Springs facility that provide the information required by Commission Rule 746-430-2(1).

A. The required information for the nominal 400 MW Cedar Springs facility is included in Confidential Exhibit RMP___(CAT-1SD) to my testimony. Confidential Exhibit RMP___(CAT-1SD) subparts are:

- Confidential Exhibit RMP___(CAT-1SD-1)–Wind Turbine Generator ("WTG") Site Layout
- Confidential Exhibit RMP___(CAT-1SD-2)–Site Wind Resource Data
- Confidential Exhibit RMP___(CAT-1SD-3)–Preliminary Project Schedule
- Confidential Exhibit RMP___(CAT-1SD-4)–Project Map
- Confidential Exhibit RMP___(CAT-1SD-5)–Metes and Bounds Property Information
- Highly Confidential Exhibit RMP___(CAT-1SD-6)–Generation Tie-line Property Information
- Confidential Exhibit RMP___(CAT-1SD-7)–Environmental Studies
- Confidential Exhibit RMP___(CAT-1SD-8)–Raptor Nest Information
- Confidential Exhibit RMP___(CAT-1SD-9)–Permitting Matrix
- Confidential Exhibit RMP___(CAT-1SD-10)–System Impact Re-Study Q712
- Confidential Exhibit RMP___(CAT-1SD-11)–230-kV Tie-line Structure Details

Q. Please describe the exhibits to your testimony for the nominal 500 MW TB Flats I and II wind facility that provide the information required by Commission Rule 746-430-2(1).

A. The required information for the nominal 500 MW TB Flats I and II wind facility is included in Confidential Exhibit RMP__(CAT-2SD) to my testimony. Confidential Exhibit RMP__(CAT-2SD) subparts that have been updated since my direct testimony was filed in this docket are:

- Confidential Exhibit RMP___(CAT-2SD-1)–Preliminary Site Layout
- Confidential Exhibit RMP___(CAT-2SD-7)–Parcel Map
- Confidential Exhibit RMP___(CAT-2SD-14)–Large Generator Interconnection Facilities Study

Q. Please describe the exhibits for the nominal 109 MW McFadden Ridge II wind facility that provide the information required by Commission Rule 746-430-2(1).

A. The required information for the nominal 109 MW McFadden Ridge II wind facility is included in Exhibit RMP___(CAT-3SD) to my testimony. Exhibit RMP___(CAT-3SD) subparts that have been updated since my direct testimony was filed in this docket are:

- Confidential Exhibit RMP___(CAT3SD-1)–WTG Site Layout

Q. Please describe the exhibits to your testimony for the nominal 161 MW Uinta wind facility that provide the information required by Commission Rule 746-430-2(1).

A. The required information for the nominal 161 MW Uinta wind facility is included in Confidential Exhibit RMP__(CAT-4SD) to my testimony. Confidential Exhibit RMP__(CAT-4SD) subparts are:

- Confidential Exhibit RMP___(CAT-4SD-1)–Project Details and Facilities

    - Confidential Exhibit RMP___(CAT-4SD-1-A)–Site Layout
    - Confidential Exhibit RMP___(CAT-4SD-1-D)–Preliminary One-Line Diagrams
    - Confidential Exhibit RMP___(CAT-4SD-1-E)–Wetlands and Surface Water
- Confidential Exhibit RMP___(CAT-4SD-2)–Site Description
    - Confidential Exhibit RMP___(CAT-4SD-2-A)–Preliminary Metes and Bounds Description
- Confidential Exhibit RMP___(CAT-4SD-3)–Geology
    - Confidential Exhibit RMP___(CAT-4SD-3-A)–Vicinity Topography
    - Confidential Exhibit RMP___(CAT-4SD-3-B)–Groundwater
    - Confidential Exhibit RMP___(CAT-4SD-3-C)–Surficial Geology
    - Confidential Exhibit RMP___(CAT-4SD-3-D)–Bedrock Geology
    - Confidential Exhibit RMP___(CAT-4SD-3-E)–Mineral Deposits
- Confidential Exhibit RMP___(CAT-4SD-4)–Natural Resources
    - Confidential Exhibit RMP___(CAT-4SD-4-A)–Visual Resources
    - Confidential Exhibit RMP___(CAT-4SD-4-B)–Visual Simulations
    - Confidential Exhibit RMP___(CAT-4SD-4-C)–Regional Summary
    - Confidential Exhibit RMP___(CAT-4SD-4-H)–Studies Status
    - Confidential Exhibit RMP___(CAT-4SD-4-I)–Environmental Studies
- Highly Confidential Exhibit RMP___(CAT-4SD-5_–Property Acquisition Status
    - Confidential Exhibit RMP___(CAT-4SD-5-B)–Landowner Map
- Confidential Exhibit RMP___(CAT-4SD-6)–Preliminary Construction Schedule

- Confidential Exhibit RMP___(CAT-4SD-7)–Site Wind Resource Data

Q. Please provide a summary of the capital expenditures required to construct the Wind Projects.

A. Confidential Exhibit RMP___(CAT-5SD) to my testimony includes the summary.

REBUTTAL TESTIMONY

Q. Several parties note that the Wind Projects must be operational by the end of 2020 to receive full PTC benefits. (*See, e.g.*, Hayet Direct, lines 249-252; Zenger Direct, lines 289-293.) How does the Company plan to ensure successful and timely delivery of the Combined Projects?

A. The Company relies on several strategies to ensure successful mitigation of the types of project-implementation risks that could delay the Combined Projects beyond 2020. The Company recently used these same strategies to successfully deliver very similar wind and transmission projects as those under review in this docket.

Perhaps most importantly, the Company built its regulatory procedural schedules and project-implementation timeline to allow sufficient time to acquire the rights-of-way ("ROW") necessary for the Aeolus-to-Bridger/Anticline transmission line. The ability to acquire necessary ROW will be known before releasing the full notice to proceed ("FNTP") to major contractors for the Combined Projects. Moreover, if there is a delay in acquiring the necessary ROW for the Transmission Projects, the Company will reassess how to adjust the projects' remaining critical-path schedules to successfully deliver customers the benefits of the Combined Projects.

Q. **Has the Company started negotiating the contracts for the Combined Projects?**

A. Yes. The Company solicited competitive market proposals and is actively negotiating contract terms, conditions, and pricing for the Wind Projects, and is engaged in similar efforts for the Aeolus-to-Bridger/Anticline transmission line, as more fully described in the rebuttal testimony of Company witness Mr. Rick A. Vail. This will ensure contract execution in a timely and efficient manner following regulatory approvals and receipt of critical permits, but also to review each potential counterparty's ability to secure and deliver labor and materials throughout its proposed construction schedules. (*See* Zenger Direct, lines 315-318.) This review considers the number and scope of concurrent projects that potential counterparties have been able to deliver historically, and their approach to booking future projects and managing that business growth in times of significant market opportunity. The early engagement of contractors and counterparties, the timely selection of contractors and shortlisted projects, and the timely approval of a CPCN from the Wyoming Public Service Commission for the projects, will allow the Company to commit and secure labor and materials from the selected contractors and counterparties for its projects before other market participants who engage in such discussions later in 2018 and 2019.

Q. Has the Company taken a similar approach to engage the market for wind turbine suppliers?

A. Yes. The Company has also solicited competitive market proposals and is actively negotiating wind turbine supply contract terms, conditions, and pricing for the Company benchmark Wind Projects. These efforts will (1) ensure timely and efficient contract execution following receipt of regulatory approvals and critical permits, and (2) secure manufacturing and delivery queue positions and schedules in support of the Wind Projects. I discussed the procurement status of wind turbine generators for the

Wind Projects earlier in this this testimony.

Q. How will the Company manage any weather-related construction-delay risk as discussed by Dr. Zenger? (Zenger Direct, line 309.)

A. The Company is actively negotiating project schedules and commercial terms with its shortlisted EPC contractors for the McFadden Ridge II and TB Flats I and II benchmark Wind Projects to address the potential for wind days, extreme weather, construction restrictions to accommodate winter ranges for certain wildlife, and other potential weather-related risks. For example, the Company has shifted construction activities such as installation of turbine foundations and collector systems from 2020 to 2019 in the proposed construction schedules to mitigate weather-related construction risk in 2020. The Company's economic analysis supporting the Combined Projects incorporates these EPC contract provisions, and similar provisions will be negotiated with the third-party build-transfer Wind Project developers.

Q. Mr. Hayet argues there is risk associated with the Company's reliance on third-party developers. (Hayet Direct, lines 498-521.) How do you respond to this risk?

A. Mr. Hayet's contention that third-party developers being responsible for constructing a significant portion of the Wind Projects introduces undue risk is inaccurate and, more importantly, unsupported given the shortlisted 2017R RFP build-transfer Wind Projects developers' commitments and contractual obligations to deliver the build-transfer projects submitted to the 2017 RFP under the prescribed commercial structure, regardless of the ratio of Company self-build options to third-party build-transfer projects. The terms of the Development Transfer Agreement provides specific provisions for the timing and scope of the TB Flats I and II benchmark project development assets transfer, to be implemented by PacifiCorp with directly assigned balance of plant EPC contracts and directly assigned wind turbine generator supply contracts. The terms of the 2017R RFP build-transfer agreements for the Cedar Springs and Uinta Wind Projects provide specific protections for the Company's rights and obligations, and for Company oversight of progress, inspection, confirmation of scope compliance, and performance guarantees with those counterparties. In addition, the third-party developers on the 2017R RFP final shortlist responsible for the Cedar Springs and Uinta build-transfer wind projects are industry leaders in wind-project development and implementation.

Q. Mr. Hayet suggests a risk that the Company's 2016 safe-harbor expenditures related to the Wind Projects may be insufficient to receive the full PTC benefits. (Hayet Direct, lines 711-718.) How has the Company mitigated this risk?

A. The Company has mitigated this risk by confirming 2016 safe-harbor wind turbine generator purchases for each of the 2017R RFP final shortlist Wind Projects with the respective project developers. Mr. Hayet's reference to the Company's direct expenditures for safe-harbor equipment in 2016 represents only a portion of safe-harbor wind turbine generator purchases required for the Wind Projects. Each of the 2017R RFP project proponents has provided the appropriate evidence of the safe-harbor purchases that will be applied to each of the respective Wind Projects.

Q. Mr. Peaco alleges that the Company has not "provided any mechanism for damage recovery due to 'lost' PTC." (Peaco Direct, lines 879-882.) How do you respond?

A. As discussed above, the Company will use various risk mitigation measures, or "mechanisms," including specific contract terms and conditions to be negotiated with

2017R RFP shortlist counterparties and contractors to avoid “lost PTC” scenarios. Specific contract terms and conditions will include, but not be limited to, project schedule and tracking requirements, performance guarantees, indemnities, and liquidated damages, all of which provide the Company with commercial “mechanisms” to proactively manage and address potential counterparty performance issues that could ultimately lead to “lost PTC.” While a competitive-market participant will not accept consequential damages related to the recovery of “lost PTC” in entirety, the Company will deploy reasonably appropriate and commercially available risk mitigation measures within the Combined Projects' implementation plans and contracts.

Q. Mr. Peaco notes a risk that the capital costs of the Wind Projects will be more than expected and thereby decrease the estimated customer benefits. (Peaco Direct, lines 961-962.) Has the Company been able to mitigate this risk?

A. Yes. By engaging the competitive market and implementing appropriate and commercially available risk-mitigation measures in its contracts for the Combined Projects, the Company is making every effort to mitigate any capital cost risks for the Combined Projects. Mr. Link provides additional detail of the economic results of the 2017R RFP and the associated positive impact to the assessment of customer benefits in his testimony, and the Company's efforts to incorporate risk mitigation into all aspects of the Combined Projects has been discussed at length in my testimony and the testimony of Mr. Vail.

Q. Does the level of risk or uncertainty of the capital cost estimates for the Combined Projects differ from the risks and uncertainty inherent in all resource acquisitions?

A. No. The Company's approach to estimate costs and then engage the competitive market during the Combined Projects' development schedules is reasonable and prudent and provides additional certainty and mitigation of capital cost risk.

Q. Mr. Peaco argues that a small reduction in production from the Wind Projects will erode the customer benefits. (Peaco Direct, lines 995-998.) What efforts has the Company taken to validate the capacity factors developed for the Wind Projects?

A. The Company engaged an independent third-party wind-resource-data technical analyst to review and determine the appropriate capacity factor estimates to incorporate into its Wind Project analyses and 2017R RFP submissions. The third-party technical assessments are based on an annual 50-percent probability ("P50") approach and provide estimated wind production over several years to account for normal and expected annual variations. By the very nature of a P50 estimate, actual wind project production is expected to be below the P50 estimate half of the years and above the P50 estimate the other half of the years. Requiring the Company to provide the full PTC and energy benefits at the higher of the P50 capacity factor or actual production is asymmetrical and unreasonable.

Q. Has the Company taken additional efforts to validate the capacity factors of the shortlisted bids in the 2017R RFP?

A. Yes. As Mr. Link testifies, the Company engaged another independent third-party wind-resource data technical analysts to review and determine the appropriate capacity factor estimates to incorporate into any final shortlist analyses. The third-party experts based their assessments on a P50 approach. This independent study is included as an exhibit to Mr. Link's supplemental direct testimony.

Q. How have the Company's Wyoming wind resources performed from 2010 through 2016, as compared to the annual capacity factors estimated for the individual projects at the time of acquisition decision-making?

A. Overall, the Company's existing wind projects in the Medicine Bow, Wyoming area near the proposed location of the Aeolus substation have out-performed the pre-construction estimates, as set forth in the following table:

WYOMING WIND CAPACITY FACTOR SUMMARY

Capacity Factor	MW	COD	Pre-Construction	Average Actual	Difference
			(non-leap years)	2010 - 2016	
SEVEN MILE HILL I	99	12/31/2008	41.3 percent	39.2 percent	-5.0 percent
SEVEN MILE HILL II	19.5	12/31/2008	39.3 percent	42.5 percent	8.1 percent
HIGH PLAINS	99	9/13/2009	35.7 percent	35.2 percent	-1.3 percent
MCFADDEN RIDGE I	28.5	9/29/2009	34.5 percent	37.2 percent	7.9 percent
DUNLAP I	111	10/1/2010	36.4 percent	40.2 percent	10.4 percent
Total	357				

Q. Why have you limited your analysis to only projects developed near the Medicine Bow area of Wyoming?

A. The Company's results with the relatively recent Wyoming wind projects that were developed near Medicine Bow, Wyoming, are better correlated and more representative of the results the Company would expect with the Wind Projects, particularly considering each of the four Wind Projects incorporated into the Application is located adjacent to the Company's existing operating sites included in the chart above.

Q. Do the results to date indicate fatal flaws or undue risk in the third-party P50 analysis the Company relies on to assess project economics and customer benefits before acquisition of new wind projects?

A. No. If anything, the data presented above indicates the Company's approach to P50 capacity factor assessment for its Wyoming projects has provided a conservative representation of results on an average basis through seven years of project operation.

Q. Is there a mechanism in place to appropriately capture the variability in resource benefits inherent with new wind projects?

A. Yes. As used with previously implemented new wind projects, the Energy Balancing Account captures the variability in resource benefits inherent with new wind projects, in conjunction with other system energy costs, and distributes those benefits to customers.

Q. Is there anything about the Wind Projects that makes the estimated capacity factor more uncertain than for other wind facilities the Company has developed?

A. No. The Company's methodology for estimating the capacity factors for the Wind Projects is the same as the methodology previously relied on by the Commission. In this respect, the Wind Projects are no riskier than any of the previous wind projects the Company has successfully developed for customers.

Q. Are customers bearing all of the risks associated with the Combined Projects?

A. No. Until the Commission reviews the implementation of a resource acquisition for prudence, the Company bears the risks. The Company anticipates that the prudence of its implementation of the Combined Projects will undergo rigorous review in Utah, and in all the other states where the Company provides retail service. In addition, as described by Mr. Link, the risks associated with the Combined Projects are no different than those associated with any other utility resource acquisition.

CONCLUSION AND RECOMMENDATION

Q. What do you conclude in your supplemental direct and rebuttal testimony?

A. The Combined Projects remain well positioned to provide customer benefits and are being effectively developed in parallel to ongoing regulatory proceedings--including the 2017R RFP, procurement activities, and upcoming permitting--to mitigate project risks and deliver desired outcomes. The Company continues to manage project-development activities within a reasonable timeline to assess project risks, incorporate those assessments into decision-making, and allow for changes in project direction (*i.e.*, off-ramps), if necessary. The Company appreciates the parties' engagement, and the Combined Projects will benefit from this rigorous stakeholder review before the Company makes major commitments to the projects.

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

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(CAT-1SD)
Docket No. 17-035-40
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Chad A. Teply

Information and Subpart Exhibits For the Cedar Springs Wind Energy Project

January 2018

Information and Subpart Exhibits
For the Cedar Springs Wind Energy Project

In support of the Application, the Company provides the following information and subpart exhibits for the Cedar Springs Wind Energy Project:

1. **Name and address of the applicant:**
   This information was provided in the application filed June 30, 2017.

2. **Type of plant, property, or facility proposed to be constructed:**
   Applicant proposes to construct a nominal 400-megawatt ("MW") wind-energy generation facility located on a site that consists of approximately 35,000 acres of leased private land located in Converse County, Wyoming.

3. **Description of facilities to be constructed including preliminary engineering specifications in sufficient detail to properly describe the principal systems and components:**
   The Cedar Springs wind energy facility will consist of wind turbine generators ("WTGs"), an electrical collector system, a collector substation, access roads, WTG foundations, an operations and maintenance building, fiber optic and/or microwave communication equipment, supervisory control and operating status data acquisition ("SCADA") control equipment, and an approximately 20-mile long interconnecting 230 kilovolt ("kV") transmission tie-line. The anticipated point of interconnection will be at the Windstar substation in Converse County, Wyoming. The WTGs are anticipated to be purchased from competing suppliers, and the balance of project work will be competitively bid and executed under an engineer, procure, and construct ("EPC") contract.
   An overview of WTG placement across the proposed project site is presented in Confidential Exhibit CAT-1SD-1. WTG placement will continue to evolve based on several factors including: field-identified sensitive environmental areas, field-identified cultural areas, landowner commentary received from future reviews of WTG placement, definitive geotechnical site studies, aviation/air-space impact reviews, and wind-resource characteristics.
   A site wind-resource assessment has been completed and summary information is presented in Confidential Exhibit RMP___(CAT-1SD-2).

4. **Rates to be charged because of the proposed construction:**
   The impact of the proposed facilities on the Company's revenue requirement and the Company's proposed ratemaking treatment is described in the testimony of Ms. Joelle R. Steward. In addition, the Company will provide service on the Transmission Projects subject to the terms and conditions of its Open Access Transmission Tariff ("OATT").

5. **Estimated total cost of the proposed construction:**
   Estimated project initial capital cost details for the Cedar Springs facility are summarized in Confidential Exhibit RMP___(CAT-5SD).

6. Manner by which the project will be financed:

The Company intends to finance the proposed wind project through its normal sources of capital, both internal and external, 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 of the proposed investment will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates. In addition, preapproval of the Company's resource decision provides important regulatory support for the Company's current credit rating. This is described in more detail in Ms. Cindy A. Crane's testimony.

7. Documentation of the financial condition of the applicant:

Rocky Mountain Power's ("RMP") current financial condition is on file with the Commission in response to the annual reporting requirements through RMP's semi-annual earnings reports or general rate case applications. The Company is financially capable of funding this project.

8. Estimated annual operating revenues and expenses expected to accrue from the project including a comparison of the overall effect on the applicant's revenues and expenses:

PacifiCorp provides the economic analysis presented in Mr. Rick T. Link's testimony and exhibits, which show the revenue stream and expenses associated with the wind projects and demonstrates that the project is a risk-adjusted, least-cost alternative to serve customer loads.

9. Estimated start and completion dates:

The project developer and PacifiCorp will enter into a build-transfer agreement under which PacifiCorp will acquire 50 percent of the project, and the balance of the project will be delivered under a power purchase agreement. The project developer will design, permit, secure property rights, obtain critical agreements, construct, and commission the project. The project developer proposes to complete environmental and cultural surveys in April 2019 and transmission line construction in April 2020. The expected proposed project commercial-operation date is December 2020, under normal construction circumstances, weather conditions, labor availability, materials delivery, and permit and agreement processing durations.

An indicative project schedule is presented in Confidential Exhibit RMP___(CAT-1SD-3).

10. Description of the site(s) including:

a. county,

   Converse County, Wyoming

b. metes and bounds description, and

   See Confidential Exhibit RMP___(CAT-1SD-4) for a project description map indicating parcels that are proposed for leased for wind and transmission development. A more specific metes bounds description is presented in Confidential Exhibit CAT-1SD-5. Tie-line property information is presented in Highly Confidential Exhibit CAT-1SD-6.

c. terrain;
   - **i.** The project site is located in central Converse County, at an elevation range of 5,000 to 5,500 feet. The terrain consists of rolling range land with a predominant southeast – northwest ridge feature (Box Creek Divide) and a northern plateau (Highland Flats). The land use consists of sheep and cattle grazing, with oil and gas exploration distributed throughout the entire site. Habitat within the project site is predominately herbaceous grasslands and scrub-shrub. Common mixed grass prairie species include needle-and-thread (Hesperostipa comata), western wheatgrass (Pascopyrum smithii), blue grama (Bouteloua gracilis), Sandberg's bluegrass (Poa secunda), prairie junegrass (Koeleria macrantha), upland sedges, and Indian ricegrass (Oryzopsis hymenoides). The scrub habitats likely consist of sagebrush (Artemesia tridentata) and various other shrub species.

11. Geological report including:

a. foundation and groundwater conditions,
   - **i.** The dominant wetland type is freshwater emergent wetland within the project site, in addition to a number of scattered ponds throughout the area. Converse County also shows a lake and a few areas mapped as riverine. There are freshwater forested/shrub wetlands located in Converse County within the vicinity of the site.

b. operating mineral deposits within a one-mile radius, and
   - **i.** Oil and gas operations are present throughout the site. Anschutz, Chesapeake and other mineral developers are active in the area.
   - **ii.** In-situ uranium mining occurs in the northwest portion of the site. A historic Exxon open-cut uranium mine exists in the northwest portion of the site, however it is no longer active.

c. A topographic map showing the area within a five-mile radius.
   - **i.** A topographical map showing the terrain of the surrounding area of the facility is provided as Confidential Exhibit RMP___(CAT-1SD-1).

d. Site geotechnical and geologic studies have not yet started.

12. Description of and plans for protecting the surrounding locations:

a. Scenic,
b. Historical,
c. Archeological,
d. Recreational,
e. Natural resources,
f. Plant and animal life,
g. Land reclamation
   - **i. Description of devices to be installed to protect:**
     1. **Air,**
     2. **Water,**
     3. **Chemical,**
     4. **Biological, and**
     5. **Thermal qualities.**

ii. **Design and tested effectiveness of protection devices to be used; and**
iii. **Operational conditions under which the protection devices were designed and tested**

The Cedar Springs facility is located in an area that is typical of the landscape of the region. The WTGs are not anticipated to significantly degrade the surrounding scenic quality of the area.

The project developer has preliminarily sited project components to mitigate potential environmental and natural resource impacts in the project area. This effort will continue as project details emerge.

Confidential Exhibit RMP___(CAT-1SD-7) presents indicative information regarding critical site environmental features to be addressed as the project proceeds.

The preliminary project layout has been arranged to avoid impacts to cultural resources. Additionally, no project related features will be developed in close proximity to known cultural resources. As part of PacifiCorp's plan for protecting the environment, sensitivity practices would be adhered to and any cultural resources would be afforded appropriate protection if discovered during design and construction.

The project has the flexibility to microsite major project features to avoid or significantly reduce impacts to jurisdictional waters of the U.S. and wetlands. More importantly, no adverse impacts to wetland and water resource bodies are anticipated for this project. Any impact to wetlands and the waters of the U.S., should they arise, will be minimized using best management practices.

At the end of project life, and in accordance with applicable permit conditions PacifiCorp may have reserved funds in its asset retirement obligation ("ARO") account and may use ARO funding to restore the site to near natural conditions.

Lands disturbed during construction would be reclaimed in accordance with applicable permit requirements. Ground disturbance would be minimized and best management practices employed by the construction contractors to minimize environmental impacts. PacifiCorp would also employ an environmental inspector(s) to ensure that environmental considerations, and any unforeseen environmental incidents, are appropriately addressed. This individual would ensure prompt and appropriate response to any identified non-compliance situations and ensure environmental protections are appropriately implemented. Periodic environmental audits of the site will also be conducted by PacifiCorp affiliated personnel that are independent of the project team.

During construction, each on-site contractor will be expected to develop, publish and orchestrate a site- and project-specific environmental protection plan.

Site specific wildlife management plans will be developed and implemented in accordance with applicable permit requirements.

Confidential Exhibit RMP___(CAT-1SD-8) presents currently known raptor nest information.

The approximate 20-mile long transmission tie-line will be included in the Wyoming Industrial Siting Act permit application for the Cedar Springs facility.

Information regarding the status of project permitting activity is presented in Confidential Exhibit CAT-1SD-9.

13. Description of potential safety hazards;

Prevention of safety hazards and impacts from failure of the project's components would be achieved by a combination of planning and controlled site access. By following industry guidelines and WTG certification processes, the most safe and reliable facility will be constructed. WTGs are equipped with multiple safety systems as standard equipment. For example, rotor speed is controlled by a redundant pitch control system and a backup disk brake system. Critical components have multiple temperature sensors and a control system to shut the system down and take it off-line if overheating conditions are detected. Lightning protection is a standard feature on the WTG, and a specially engineered lightning protection and site grounding system will be installed for the project.

Turbine towers, WTG foundations, and above-ground transmission line support structures will be designed according to applicable building codes and nationally accepted design standards to avoid failure or collapse. The selected WTG and tower combination will be subjected to engineering review to ensure that the design and construction specifications are appropriate for the project. This review will include consideration of code/nationally accepted design standard requirements under various anticipated worst-case loading conditions and will provide a high degree of confidence in the structural adequacy of the towers. The WTGs have been preliminarily sited at locations which exceed a reasonable setback of over one tip-height.

During active construction, the project developer will follow the manufacturers' recommended handling instructions and erection procedures to prevent material damage to towers or blades that could lead to failure. In addition, certification of the WTG to the requirements of the *International Electrotechnical Commission ("IEC") 61400-1* standard will be provided to ensure that the static, dynamic, and defined-life fatigue stresses in the blades will not be exceeded under the combined load combinations expected at the project site. The standard includes safety factors for normal, abnormal, fatigue, and construction loads. This certification, together with regular periodic inspections, will give a high level of assurance against blade failure during operation.

The WTGs will be sited at locations that exceed a reasonable set-back distance to safeguard against ice throw. No ice throw injury has been reported from existing wind generation projects. In general, icing is an infrequent event, and the turbines for this project will be situated in a remote area.

During construction, planned construction safety controls include a "Site Specific Safety Plan."

The WTGs will be grouped in strings, and some of the WTGs will include aviation warning lights, as required by the Federal Aviation Agency ("FAA"). The number of WTGs with lights and the lighting pattern of the WTG will be determined through collaboration with the FAA.

14. Description of real property, fuel and water requirements, including any source of water along which the facility will be constructed or from which it will obtain or return water;

There are no fuel, minerals, or process water requirements for this project.

At the time of this supplemental filing, it is anticipated that during project construction, water will be obtained from a municipal water source, an existing senior water rights holder and trucked to the site, or a new well with a permit issued by the Wyoming State Engineer's Office to appropriate groundwater. Once available on-site, water will either be put to immediate use or placed in an onsite temporary water storage tank. Once the project is in operation, only minimal daily domestic water use will be required. The primary domestic water requirement will occur at the O&M building, and is anticipated to be limited to consumption in restrooms, sinks, washing station(s), showers, internal/external hose use, and as dishwater.

A septic system and drain field for sanitary sewer waste disposal will be provided once the project is operational.

15. Acquisition status, source and location of:

- **a. Real property,**
- **b. Right-of-way,**
- **c. Fuel, and**
- **d. Water requirements**

The Cedar Springs facility will be located on private property currently under long-term lease, the area as described in Confidential Exhibit RMP___(CAT-1SD-4). The transmission tie-line will primarily cross private property and will avoid federal lands to the maximum extent possible. Final transmission routing and ROW acquisition will begin in April 2018.

There are no fuel acquisition requirements for this project. A groundwater use application will be applied for from the Wyoming State Engineer's Office for a new extraction well.

16. Proposed means of transporting fuel and water requirements;

There is no process-related requirement to transport material quantities of fuel and water for this project.

17. Description of all mineral rights associated with the facility and plans for addressing any split-estate issues;

Mineral rights across the site are split between State and Federal governments and third party holdings, the majority of which have been severed from the surface owner. The State's mineral rights are generally tied to the surface rights, however there are rare exception, predominantly near water ways, where there may be exceptions to this.

The project is expecting to enter into accommodation agreements with the mineral rights holders across the project to resolve any split-estate issues.

18. Statement detailing the need for the facility in meeting present and future demands for service in Utah or other states;

Development of the proposed wind generation facility in compliance with regulatory requirements is the risk adjusted least cost alternative to meet service obligations in Utah and other states as represented in the Company's testimony and exhibits. The Company's forward looking generation planning activities are further described in the Company's 2017 IRP.

19. Description of the commodity or service the facility will make available;

The project will generate electricity using wind as the renewable energy source. Fossil fuel consumption and waste residual disposal obligations will be avoided.

20. Statement of the effect on the system stability and reliability; and

The project is not expected to adversely affect the quality, stability, and reliability of the Rocky Mountain Power ("RMP") transmission system or that of other entities. Large generator interconnection "System Impact Re-Study Report" is provided as Confidential Exhibit RMP___(CAT-1SD-10) that summarizes the expected impact.

Confidential Exhibit RMP___(CAT-1SD-11) presents images of the 20-mile 230 kV tie-line and tie-line structures.

21. Status of local, state, Tribal, or federal governmental agency requirements (must file all agencies final orders)

a. Local – A Wind Energy Conversion System ("WECS") Use Permit is required in Converse County. The project is anticipating filing and obtaining a WECS Use Permit in 2018
b. State – A Wyoming Department of Environmental Quality Industrial Siting Council ("ISC") Permit is required for wind energy project with 30 or more towers in all phases. An application will be submitted to ISC in 2018 with approval anticipated in late 2018 or 2019.
c. Federal – No NEPA approval is required for the project.
d. Tribal – No Tribal permit is required for the project.
e. A list of the local, state, tribal, and federal governmental agencies having requirements known at the time of this application, which PacifiCorp must meet in connection with the construction and operation of the project is listed, along with their timing and status, in Confidential Exhibit RMP___(CAT-1SD-9). Any unforeseen permit requirements will be adequately addressed.
f. By applying to and working with the various agencies for the construction/operation permits and the Commission, the major regulatory requirements and critical reviews for the project are being addressed. PacifiCorp's contractors may provide certain permits including permits for construction storm water pollution prevention control, compliance with building regulations through the Carbon County Planning and Zoning Commission, sanitary sewer extensions, and requirements of the Wyoming Department of Transportation. PacifiCorp will monitor and audit the successful completion, maintenance, and closeout of all contractor supplied permits.

The following documents included in Exhibit RMP___(CAT-1SD) are confidential or highly confidential in their entirety:

Confidential Exhibit RMP (CAT 1SD-1)	Cedar Springs WTG Layout
Confidential Exhibit RMP (CAT 1SD-2)	Cedar Sprints Site Wind Resource Data
Confidential Exhibit RMP (CAT 1SD-3)	Cedar Springs Preliminary Project Schedule
Confidential Exhibit RMP (CAT 1SD-4)	Cedar Springs Project Maps
Confidential Exhibit RMP (CAT 1SD-5)	Cedar Springs Metes and Grounds Descriptions
Highly Confidential Exhibit RMP (CAT 1SD-6)	Cedar Springs Generation Landowner Information
Confidential Exhibit RMP (CAT 1SD-7)	Cedar Springs Environmental Studies
Confidential Exhibit RMP (CAT 1SD-8)	Cedar Springs Raptor Nest Information
Confidential Exhibit RMP (CAT 1SD-9)	Cedar Springs Permitting Matrix
Confidential Exhibit RMP (CAT 1SD-10)	Cedar Springs System Impact Re-Study Q712
Confidential Exhibit RMP (CAT 1SD-11)	Cedar Springs 230 kV Tie Line Structure Details

The confidential exhibits listed above are provided on CD.

The highly confidential exhibits contain commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request. The Company requests special handling. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

REDACTED
Rocky Mountain Power
Exhibit RMP___(CAT-2SD)
Docket No. 17-035-40
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Chad A. Teply

Information and Subpart Exhibits For the TB Flats I and II Wind Energy Project

January 2018

Information and Subpart Exhibits
For the TB Flats I and II Wind Energy Project

(A) The name and address of the applicant:

This information was provided in the application on June 30, 2017.

(B) The type of plant, property, or facility proposed to be constructed or acquired:

PacifiCorp proposes to construct a 500-megawatt (nominal) project designated as the TB Flats I and II project. The project is located on a site that consists of approximately 50,000 acres of leased private and state land located in Wyoming's Carbon and Albany Counties.

(C) A description of the facilities proposed to be constructed or acquired, including preliminary engineering specifications in sufficient detail to properly describe the principal systems and components, and final and complete engineering specifications when they become available:

The TB Flats I and II wind energy project will consist of wind turbine generators ("WTGs"), an electrical collector system, a collector substation, access roads, WTG foundations, an operations and maintenance building, fiber optic and/or microwave communication equipment, permanent meteorological towers, wind-measurement equipment, and supervisory control and operating status data acquisition ("SCADA") control equipment. For the TB Flats I and II project, this facility includes an interconnecting 230 kV transmission tie-line, and the anticipated point of interconnection will be at the Shirley Basin substation. The WTG supply and balance of project engineer, procure, and construct ("EPC") contracts were competitively bid, and negotiations continue toward reaching final contract terms.

Updated maps of the WTG placement across the proposed project sites is presented in Confidential Exhibit RMP___(CAT-2SD-1). WTG placement will continue to evolve based on several factors, including: land acquisition, field identified sensitive environmental and cultural areas, landowner commentary received from future WTG placement reviews, definitive geotechnical site studies, aviation / air space impact reviews, site access availability, and wind resource characteristics.

Confidential Exhibit RMP___(CAT-2-2) was provided previously as an example of a WTG purchase agreement, including specifications. (Exhibits that have not been updated are not resubmitted in this CPCN filing supplement.)

Confidential Exhibit RMP___(CAT-2-3) was provided previously as an example of a technical specification for the scope of work included in a balance of project EPC contract.

(D) List the rates, if any, proposed to be charged for the service that will be rendered because of the proposed construction or acquisition:

The impact of the proposed facilities on the Company's revenue requirement and the Company's proposed ratemaking treatment is described in the testimony of Ms. Joelle R. Steward. In addition, the Company will provide service on the Transmission Projects subject to the terms and conditions of its Open Access Transmission Tariff ("OATT").

(E) State the estimated total cost of the proposed construction or acquisition:

At the time of the supplemental filing, updated estimated project cost details are summarized in Confidential Exhibit RMP___(CAT-5SD).

(F) State the manner by which the proposed construction or acquisition will be financed:

The Company intends to finance the proposed wind project through its normal sources of capital, both internal and external, 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 of the proposed investment will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates. In addition, preapproval of the Company's resource decision provides important regulatory support for the Company's current credit rating. This is described in more detail in Ms. Cindy A. Crane's testimony.

(G) Documentation of the financial condition of the applicant:

Rocky Mountain Power's ("RMP") current financial condition is on file with the Commission in response to the annual reporting requirements through RMP's semi-annual earnings reports or general rate case application. The Company is financially capable of funding this project.

(H) The estimated annual operating revenues and expenses that are expected to accrue from the proposed construction or acquisition, including a comparison of the overall effect on the applicant's revenues and expenses:

To address this requirement of the Commission's rules, PacifiCorp provides the economic analysis presented in Mr. Rick T. Link's testimony and exhibits, which show the revenue stream and expenses associated with the wind projects and demonstrates that the project is a risk-adjusted, least-cost alternative to serve customer loads.

The approximate operational, maintenance, and ongoing capital costs expected as a result of each project are presented in previously provided Confidential Exhibit RMP___(CAT-2-5). Wind lease related costs are included in these amounts. Routine maintenance of the WTG will be necessary to maximize performance and detect potential malfunctions. Operational and maintenance ("O&M") procedures will be established in accordance with the WTG manufacturer's recommendations. Scheduled maintenance will be conducted on each WTG. Substations, step-up transformers, and pad-mounted transformers will be maintained as part of normal operating activities. Periodic maintenance of underground collection lines will also be required. No substantial quantities of industrial materials will be brought onto or removed from the site during execution of O&M tasks. Project operation will use lubricants, oils, grease, antifreeze, degreasers, and hydraulic fluids, which will be stored in approved containers and located aboveground. During operation, it is also anticipated that hazardous waste generation will be minimal. A minimal amount of energy will be required to operate the project. O&M costs reported include labor, employee expenses, materials, and contracts.

(I) The estimated start and completion dates of the proposed construction or date of acquisition:

PacifiCorp proposes to begin engineering and construction of the project in June 2018, but with only limited construction activities occurring in 2018. The proposed project commercial operation operating date is November 1, 2020, under normal construction circumstances, weather conditions, labor availability, materials delivery, and permit/agreement processing durations. An indicative project execution schedule for the project was previously provided as Confidential Exhibit RMP___(CAT-2-6).

(J) A description of the proposed site, including the county or counties in which the facility will be located, with a metes and bounds description, and a description of the terrain where the facility will be constructed:

The site footprint spans Township ("T") 27 North ("N") and Range ("R") 78 West ("W") of the sixth principle meridian in the north direction; T 23 N and R 78 W in the south direction; T 26 N and R 78 W and T 25 N and R 78 W in the west direction; and to east direction, extending into Albany County at parcel T 25 N and R 77 W. The town of Medicine Bow is located approximately five miles to the south of the project south boundary. The project site varies in elevation, with a representative elevation of approximately 6,700 feet above mean sea level.

Mountain elevations in the area rise to approximately 8,300 feet. The site drainage follows the path of Muddy Creek and tributaries, which are tributary to the Medicine Bow River that joins the North Platte River at the Seminoe Reservoir located to the northwest. Updated Confidential Exhibit RMP___(CAT-2SD-7) presents a map of area surface ownership.

(K) A geological report of the proposed site, including foundation conditions, groundwater conditions; operating mineral deposits within a one-mile radius and a topographical map showing the area within a five-mile radius:

Confidential Exhibit RMP___(CAT-2-8), previously provided, is a geotechnical report for the Dunlap Ranch Wind Energy facility and was provided as proxy geological and foundation information for the TB Flats I and II facility. Regional geologic conditions are summarized within the Dunlap geotechnical report.

Also, according to the U.S. Geological Survey Digital Geologic Map of Wyoming, the project area intersects fifteen geologic formations. These include the: Chugwater Formation, Clovery Formation, Ferris Formation, Frontier Formation, Goose Egg Formation, Lewis Shale, Medicine Bow Formation, Mesaverde Formation, Mowry Shales, Niobrara Formation, Steele Shale, Wind River Formation, Sundance Formation, Tensleep Sandstone Formation, and Amsden Formation.

The project area is anticipated to be within the Lower Cretaceous aquifer. Groundwater wells in the area varies in depth from 45 to 99 feet below ground surface ("bgs"), with well static water levels ranging from three to 20 feet bgs.

PacifiCorp will continue to assess the impacts of any operating mineral deposits approximately within a one mile radius of the facility. This project is not expected to affect operating mineral deposits or oil and gas leases.

A topographical map showing the terrain of the surrounding area within a five-mile radius of the facility was provided previously as Confidential Exhibit RMP___(CAT-2-9).

(L) A description of and plans for protecting the surrounding scenic, historical, archeological and recreational locations; natural resources; plant and animal life; and land reclamation, including: (I) A general description of the devices to be installed at the major utility facility to protect air, water, chemical, biological and thermal qualities; (II) The designed and tested effectiveness of such devices; and (III) The operational conditions for which the devices were designed and tested:

Confidential Exhibit RMP___(CAT-2-10), provided previously, presents information on nearby area scenic byways, recreational locations, national parks, and state parks. To the east of the project site, located along Wyoming Highway 487, is the historic Sand Creek Massacre Trail. The trail was dedicated on August 16, 2006. The trail exists in Wyoming as a memorial to the Arapaho and Cheyenne who lost their lives at the Sand Creek Massacre in Colorado in 1864. Impacts to visual resource concerns should be minimal because of the rural setting of the project. The project will be sited adjacent to existing wind projects with similar visual impacts. The WTGs are not anticipated to significantly degrade the surrounding scenic quality of the area.

PacifiCorp has preliminarily sited project components to avoid and / or minimize potential environmental and natural resource impacts in the project area. This effort will continue as details for each project emerges.

Confidential Exhibit RMP___(CAT-2-11), provided previously, presents information on known cultural and paleontological resources at the project sites. The preliminary project layout has been arranged to avoid and / or minimize impacts to cultural resources. As part of PacifiCorp's plan for protecting the environment, sensitivity practices would be adhered to and any cultural resources would be afforded appropriate protection required by the State Historic Preservation Office in the event of a discovery during design and construction.

The project has the flexibility to "microsite" major project features to avoid or significantly reduce impacts to jurisdictional waters of the U.S. and wetlands. More importantly, no permanent losses of wetland and water resource bodies are anticipated for this project. Any impact to wetlands and the waters of the U.S., should they arise, will be minimized using best management practices.

The project area lies within the Rolling Sagebrush Steppe, Foothill Shrublands, and Low Mountains Ecoregions. Within these areas, Wyoming big sagebrush, rabbitbrush, prickly pear, wheatgrass, and fescues are common. In rock outcrop areas, juniper and mountain mahogany are also expected. The lowland plain zones, a variable brush layer of tall big sagebrush, greasewood, bunchgrasses, forbs, and prickly pear have been observed. In upland areas, mountain big sagebrush, mountain mahogany, bunchgrasses, forbs, and prickly pear / pincushion cacti have been observed. Occasionally, more diverse riparian communities are present along spring-fed draws, where red willow, chokecherry, currants, various tall grasses, various reeds, forb varieties, thistle, Indian paintbrush are present. Currently, no rare or unique vegetative communities are documented or have been currently mapped within the project area. Therefore, it is not anticipated that the project will contribute to degradation of these resources.

Wild animals including mule deer, whitetail deer, pronghorn antelope, coyotes, chipmunks, prairie dogs, ground squirrels, and rattlesnakes have been observed. Birds including red-tailed hawks, golden eagles, bald eagles, nighthawks, sparrows and various songbirds have been observed. Construction of the project will potentially cause temporary displacement of individuals for some wildlife species that may relocate in response to project activities, and lead to permanent impacts to wildlife.

Wildlife impact studies are on-going and PacifiCorp will utilize recommendations from existing U.S. Fish and Wildlife Service and Wyoming Game and Fish Department guidance documents to implement appropriate avoidance, minimization, and mitigation practices.

No currently occupied greater sage-grouse leks are located within project area.

PacifiCorp will continue to collect bat use data within the proposed project area.

Wildlife and plant species of potential concern that continue to be assessed are presented in previously provided Confidential Exhibit RMP___(CAT-2-12), including U.S. Fish and Wildlife Service listed species, Wyoming Game and Fish Department species of greatest conservation need, and Bureau of Land Management sensitive species.

At the end of project life, PacifiCorp will have reserved funds in its asset retirement obligation ("ARO") account and will use ARO funding to restore the site to near natural conditions.

Lands disturbed during construction would be reclaimed to current conditions to the extent practicable. Ground disturbance would be minimized and best management practices employed by the construction contractors to minimize environmental impacts. PacifiCorp would also employ an environmental inspector(s) to ensure that environmental considerations, and any unforeseen environmental incidents, are appropriately addressed. This individual would ensure prompt and appropriate response to any identified non-compliance situations and ensure environmental protections are appropriately implemented. Periodic environmental audits of the site will also be conducted by PacifiCorp affiliated personnel that are independent of the project team.

During construction, each on-site contractor will be expected to develop, publish and orchestrate a site and project specific environmental protection plan.

Site specific wildlife management plans will be developed and implemented.

(M) A description of any potential safety hazards:

Prevention of safety hazards and impacts from failure of the project's components will be achieved by a combination of planning and controlled site access. By following industry guidelines and WTG certification processes, the most safe and reliable facility will be constructed. WTGs are equipped with multiple safety systems as standard equipment. For example, rotor speed is controlled by a redundant pitch control system and a backup disk brake system. Critical components have multiple temperature sensors and a control system to shut the system down and take it off-line if overheating conditions are detected. Lightning protection is a standard feature on the WTGs, and a specially engineered lightning protection and site grounding system will be installed for the project.

Turbine towers, WTG foundations, and above ground transmission line support structures will be designed according to applicable building codes and nationally accepted design standards to avoid failure or collapse. The selected WTG and tower combination will be subjected to engineering review to ensure that the design and construction specifications are appropriate for the project. This review will include consideration of code / nationally accepted design standard requirements under various anticipated worst case loading conditions to provide a high degree of confidence in the structural adequacy of the towers. The WTG have been preliminarily sited at locations which exceed a reasonable set-back of over one tip-height.

During active construction, PacifiCorp will follow the manufacturers' recommended handling instructions and erection procedures to prevent material damage to towers or blades that could lead to a failure. In addition, certification of the WTG to the requirements of the *International Electrotechnical Commission ("IEC") 61400-1* standard to ensure that the static, dynamic, and defined-life fatigue stresses in the blades will not be exceeded under the combined load combinations expected at the project site. The standard includes safety factors for normal, abnormal, fatigue, and construction loads. This certification, together with regular periodic inspections, will give a high level of assurance against blade failure during operation.

The WTG will be sited at locations that exceed a reasonable set-back distance to safeguard against ice throw. No ice throw injury has been reported from existing wind generation projects. In general, icing is an infrequent event, and the turbines for this project will be situated in a remote area.

During construction, planned construction safety controls include: (1) a "PacifiCorp Safety Plan," and (2) the EPC contractor's "Site Specific Safety Plan."

The feasibility of each project site from an aviation and airspace point of view is presented in previously provided Confidential Exhibit RMP___(CAT-2-13). The WTGs will be grouped in strings, and some of the WTGs will include aviation warning lights, as required by the Federal Aviation Agency ("FAA"). The number of WTGs with lights and the lighting pattern of the WTGs will be determined through collaboration with the FAA.

(N) A description of the real property, fuel and water requirements, including any source of water along which the major utility facility will be constructed or from which it will obtain or return water:

There are no fuel, minerals, or process water requirements for this project.

The projects will be constructed in the vicinity and above the Medicine Bow River drainage.

At the time of this filing, it is anticipated that during construction of the projects, water will be obtained from a municipal water source; an existing senior water rights holder and trucked to the site; or a new well with a permit issued by the Wyoming State Engineer's Office to appropriate groundwater. Once available on-site, water will either be put to immediate use or placed in an on-site temporary water storage tank. Once the project is in operation, only minimal daily domestic water use will be required. The primary domestic water requirement will occur at the operations / maintenance building, and is anticipated to be limited to consumption in restrooms, sinks, washing station(s), showers, internal / external hose use, and as dishwater.

A septic system and drain field for sanitary sewer waste disposal will be provided once the project is operational.

(O) The acquisition status, source and location of real property, right-of-way, fuel and water requirements:

Property and right-of-way acquisition status was mentioned previously. There are no fuel acquisition requirements for these projects. A groundwater use application will be applied from the Wyoming State Engineer's Office if a new extraction well is necessary.

(P) The proposed means of transporting fuel and water requirements:

There is no process related requirement to transport material quantities of fuel and water for these projects.

(Q) A description of all mineral rights associated with the facility and plans for addressing any split-estate issues:

PacifiCorp will not own any of the subsurface rights at the site. The Company does not believe that any subsurface right holder will be able to unreasonably displace the resource or any portion of the resource.

PacifiCorp has completed prudent legal research on its rights as a surface lease holder, as compared to those of subsurface right holders, and is comfortable that the law does not allow subsurface right holders to unilaterally displace the Company's facilities and that any subsurface right holder would be required to enter into good faith negotiations to reasonably accommodate its subsurface extraction objective. The Company plans to approach any active minerals extraction company with operating facilities, permits secured, or planned activities to secure appropriate agreement(s), which would detail the manner in which both the Wind Project and the subject minerals activity could coexist.

(R) A statement setting forth the need for the facility in meeting present and future demands for service in Wyoming and other states:

Development of the proposed wind generation facilities in compliance with regulatory requirements is the risk adjusted least cost alternative to meet service obligations in Wyoming and other states as represented in the Company's testimony and exhibits. The Company's forward looking generation planning activities are further described in the Company's 2017 IRP.

(S) A description of the commodity or service the facility will make available:

The project will generate electricity using wind as the renewable energy source. Fossil fuel consumption and waste residual disposal obligations will be avoided.

(T) A statement of the facilities effect on the applicant's and other systems' stability and reliability:

Each project is not expected to adversely affect the quality, stability, and reliability of the Rocky Mountain Power ("RMP") transmission system or that of other entities. An updated large generator interconnection "Facilities Study Report" is provided as Confidential Exhibit RMP___(CAT-2SD-14) that summarizes the expected impact for the TB Flats I facility.

An updated large generator interconnection "Facilities Study Report" is provided as Confidential Exhibit RMP___(CAT-2SD-14) that summarizes the expected impact for the TB Flats II facility.

It is further reported that the transmission provider will be further revising the updated TB

Flats “Facilities Study Reports.”

(U) The status of satisfying local, state, Tribal or federal governmental agency requirements. The applicant shall immediately fill all agencies’ final orders:

A list of the local, state, Tribal, and federal governmental agencies having requirements known at the time of this application, which PacifiCorp must meet in connection with the construction and operation of each project is listed, along with their timing and status, in previously provided Confidential Exhibit RMP___(CAT-2-16). Any unforeseen permit requirements will be adequately addressed.

By applying to and working with the various agencies for the construction / operation permits and the Commission, the major regulatory requirements and critical reviews for the project are being addressed. PacifiCorp’s contractors may provide certain permits including permits for construction storm water pollution prevention control, compliance with building regulations through the Carbon County Planning and Zoning Commission, Albany County Planning and Zoning Commission, sanitary sewer extensions, and requirements of the Wyoming Department of Transportation. PacifiCorp will monitor and audit the successful completion, maintenance and closeout of all contractor supplied permits.

The following documents included in Exhibit RMP___(CAT-2SD) are confidential in their entirety:

Confidential Exhibit RMP (CAT 2SD-1)	TB Flats I and II WTG Layout
Confidential Exhibit RMP (CAT 2SD-7)	TB Flats I and II Landowner Map
Confidential Exhibit RMP (CAT 2SD-14)	TB Flats I and II Large Generator Interconnection Report

The confidential exhibits listed above are provided on CD.

REDACTED
Rocky Mountain Power
Exhibit RMP___(CAT-3SD)
Docket No. 17-035-40
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Chad A. Teply

Information and Subpart Exhibits For the McFadden Ridge II Wind Energy Project

January 2018

Information and Subpart Exhibits For the McFadden Ridge II Wind Energy Project

(A) The name and address of the applicant:

This information was provided in the application on June 30, 2017.

(B) The type of plant, property, or facility proposed to be constructed or acquired:

PacifiCorp proposes to construct 110 megawatts (nominal) of wind energy generation capacity adjacent to its existing High Plains/McFadden Ridge I wind energy generation facility. This lateral expansion project (named McFadden Ridge II) is located to the south, and exclusively consists of approximately 5,500 acres of wind lease private and state of Wyoming land in Carbon and Albany Counties. Note that the proposed infrastructure will not require the use of any federal public lands, managed by the Bureau of Land Management.

(C) A description of the facilities proposed to be constructed or acquired, including preliminary engineering specifications in sufficient detail to properly describe the principal systems and components, and final and complete engineering specifications when they become available:

The McFadden Ridge II facility will consist of wind turbine generators ("WTGs"), an electrical collector system, a collector substation, access roads, WTG foundations, fiber optic and/or microwave communication equipment, supervisory control and operating status data acquisition ("SCADA") control equipment, permanent meteorological towers with wind measurement equipment, and an interconnecting 230 kilovolt ("kV") transmission line tap to the McFadden Ridge I/High Plains substation radial tie-line from the existing Foote Creek Rim substation. The WTG supply and the balance of project engineer, procure, and construct ("EPC") contracts were competitively bid, and negotiations to reach final contract terms continue.

An updated map of the proposed project area is presented in Confidential Exhibit

RMP___(CAT-3SD-1), which presents an overview of WTG placement across the site. WTG placement will continue to evolve based on several factors, including: field identified sensitive environmental and cultural areas, landowner commentary received from future WTG placement reviews, definitive geotechnical site studies, aviation / air space impact reviews, site access availability, and wind resource characteristics.

Confidential Exhibit RMP___(CAT-3-2) was provided previously as an example of a WTG purchase agreement, including specifications.

Confidential Exhibit RMP___(CAT-3-3) was provided previously as an example of a technical specification for the scope of work included in the balance of project EPC contract.

(D) List the rates, if any, proposed to be charged for the service that will be rendered because of the proposed construction or acquisition:

The impact of the proposed facilities on the Company's revenue requirement and the Company's proposed ratemaking treatment is described in the testimony of Ms. Joelle R. Steward. In addition, the Company will provide service on the Transmission Projects subject to the terms and conditions of its Open Access Transmission Tariff ("OATT").

(E) State the estimated total cost of the proposed construction or acquisition:

At the time of the supplemental filing, updated estimated project cost details are summarized in Confidential Exhibit RMP__(CAT-5SD).

(F) State the manner by which the proposed construction or acquisition will be financed:

The Company intends to finance the proposed wind project through its normal sources of capital, both internal and external, 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 of the proposed investment will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates. In addition, preapproval of the Company's resource decision provides important regulatory support for the Company's current credit rating. This is described in more detail in Ms. Cindy A. Crane's testimony.

(G) Documentation of the financial condition of the applicant:

Rocky Mountain Power's ("RMP") current financial condition is on file with the Commission in response to the annual reporting requirements through RMP's semi-annual earnings reports or general rate case applications. The Company is financially capable of funding this project.

(H) The estimated annual operating revenues and expenses that are expected to accrue from the proposed construction or acquisition, including a comparison of the overall effect on the applicant's revenues and expenses:

PacifiCorp provides the economic analysis presented in Mr. Rick T. Link's testimony and exhibits, which show the revenue stream and expenses associated with the wind projects and demonstrates that the project is a risk-adjusted, least-cost alternative to serve customer loads.

The approximate operational, maintenance and ongoing capital costs expected as a result of this project were presented in previously provided Confidential Exhibit RMP___(CAT-3-5). Wind lease related costs are included in these amounts. Routine maintenance of the WTGs will be necessary to maximize performance and detect potential malfunctions. Operational and maintenance ("O&M") procedures will be established in accordance with the WTG manufacturer's recommendations. Scheduled maintenance will be conducted on each WTG. Substations, step-up transformers, and pad-mounted transformers will be maintained as part of normal operating activities. Periodic maintenance of underground collection lines will also be required. No substantial quantities of industrial materials will be brought onto or removed from the site during execution of O&M tasks. Project operation will use lubricants, oils, grease, antifreeze, degreasers, and hydraulic fluids, which will be stored in approved containers and located aboveground. During operation, it is also anticipated that hazardous waste generation will be minimal. A minimal amount of energy will be required to operate the project. O&M costs reported include labor, employee expenses, materials, and contracts.

(I) The estimated start and completion dates of the proposed construction or date of acquisition:

PacifiCorp proposes to begin engineering and construction of the project in June 2018, but with only limited activities occurring in 2018. The proposed project commercial operation operating date is November 1, 2020, under normal construction circumstances, weather conditions, labor availability, materials delivery, and permit and agreement processing durations. An indicative project execution schedule was previously provided as Confidential Exhibit RMP___(CAT-3-6).

(J) A description of the proposed site, including the county or counties in which the facility will be located, with a metes and bounds description, and a description of the terrain where the facility will be constructed:

The project footprint spans across Township ("T") 20 North ("N") and Range ("R") 77 West ("W") of the sixth principle meridian and T 19 N and R 77 W. The town of McFadden is located approximately two miles to the west of the project area. The western side of the proposed project is located in Wyoming's Carbon County and the eastern side in Albany County.

The project lies within the drainage system of Coalbank Creek and its tributaries, which are tributaries to Rock Creek. Rock Creek occurs approximately three miles north of the site. Livestock ranching operations occur on a majority of the proposed project area. The elevation throughout the site ranges from approximately 7,100 to 7,400 feet above mean sea level.

Confidential Exhibit RMP___(CAT-3-7), previously provided, presents a map of area surface ownership, along with a table that provides the legal description of the project location. The project will be located on leased private fee lands owned by the Dunmire Ranch Company and Sims Land and Livestock, Inc. and on lands owned by the state of Wyoming. PacifiCorp has obtained a Special Use Lease from the Wyoming School and Land Board Trust for state-owned parcels within the project boundary.

(K) A geological report of the proposed site, including foundation conditions, groundwater conditions; operating mineral deposits within a one-mile radius and a topographical map showing the area within a five-mile radius:

The North Platte River Basin contains a wide variety of geologic formations and structural elements. Geologic formations vary in thickness and range from crystalline bedrock to alluvial deposits. The project is located in the Laramie Basin, which is a wide intermontane valley situated between the Medicine Bow Mountains to the west and the Laramie Mountains to the east. Bedrock geology in the project area consists of gravel, pediment, and fan deposits; Lewis shale; the Hanna formation; and the Medicine Bow formation. Gravel, pediment, and fan deposits in the project area are dominated by quartzite, with cobbles, pebbles, and gravels, located close to the ground surface. Lewis shale is a dark gray marine deposit that crops out along the eastern margins of the Great Divide and Washakie basins in south-central Wyoming. It consists of at least twenty depositional sequences that contain isolated sandstone and siltstone beds. Bentonite beds also are present in the lower part of the Lewis shale. The Hanna formation is a non-marine sedimentary stratum that was deposited as outwash during the Laramide Orogeny and was subsequently folded and eroded in places, forming a hogback ridge. Its composition varies from shale to sandstone and conglomerate, but within the project area it is dominated by quartzite conglomerate. As with the Hanna formation, the Medicine Bow formation occurs at ground surface and is composed of coal, carbonaceous shale, and sandstone alluvial plan deposits.

Confidential Exhibit RMP___(CAT-3-8), previously provided, presents preliminary geotechnical reports for the McFadden Ridge I and High Plains wind energy facilities that were provided as proxy foundation information for the McFadden Ridge II wind energy facility.

The primary aquifer systems used in the project area are described as quaternary (alluvial deposits) and late cretaceous aquifer systems in the northern area and early tertiary aquifer systems in the southern area. The direction of groundwater movement in the alluvium of the stream valleys is generally downstream and toward the stream, and most streams in the area derive some of their flow from groundwater. The primary source of recharge is from infiltration of snowmelt and runoff water. The majority of groundwater use in the area is for agricultural and domestic purposes.

Groundwater wells within the area vary in depth from 40 to 225 feet below ground surface ("bgs") with static water levels ranging from 12 to 118 feet bgs.

PacifiCorp will continue to assess the impacts of any operating mineral deposits approximately within a one mile radius of the facility. This project is not expected to affect operating mineral deposits or oil and gas leases.

A topographical map showing the terrain of the surrounding area within a five-mile radius of the facility was provided previously as Confidential Exhibit RMP___(CAT-3-9).

(L) A description of and plans for protecting the surrounding scenic, historical, archeological and recreational locations; natural resources; plant and animal life; and land reclamation, including: (I) A general description of the devices to be installed at the major utility facility to protect air, water, chemical, biological and thermal qualities; (II) The designed and tested effectiveness of such devices; and (III) The operational conditions for which the devices were designed and tested:

Confidential Exhibit RMP___(CAT-3-10), provided previously, presents information on area scenic byways, recreational locations, national parks, and state parks. The Edness Kimball Wilkins, Glendo, Seminoe, and Pathfinder State parks are located in the region, along with Ayers Natural Bridge and Pathfinder National Wildlife Refuge recreation facilities. Impacts to visual resource concerns should be minimal because of the rural setting of the project and the existing WTGs located adjacent to the project. The WTGs are not anticipated to significantly degrade the surrounding scenic quality of the area.

PacifiCorp has preliminarily sited project components to avoid and / or minimize potential environmental and natural resource impacts in the project area. This effort will continue as project details emerge.

Confidential Exhibit RMP___(CAT-3-11), provided previously, presents information on known cultural and paleontological resources at the project site. The preliminary project layout has been arranged to avoid and / or minimize impacts to cultural resources. It is anticipated that no National Register of Historic Places eligible archeological sites will be affected by the project. As part of PacifiCorp's plan for protecting the environment, sensitivity practices would be adhered to and any cultural resources would be afforded appropriate protection in the event of a discovery during design and construction.

A wetland delineation report is presented in previously provided Confidential Exhibit RMP___(CAT-3-12). Based on the preliminary site layout, it is anticipated that all potential impacts on jurisdictional waters of the U.S. and wetlands are currently associated with the construction of access roads. Therefore, it is concluded that the project will likely qualify for use of U.S. Army Corps of Engineers Nationwide Permit 12 for utility line construction activities, including access roads. Any impact to wetlands and the waters of the U.S. will be minimized using best management practices, including installation of culverts. Cumulative impacts are not expected to be significant.

The project area lies within the Wyoming Basin ecoregion. The Wyoming Basin ecoregion is found in portions of Colorado, Idaho, Montana, Utah, and Wyoming. This ecoregion is a broad intermontane basin dominated by arid grasslands and shrublands supporting bunchgrasses and sagebrush, interrupted by high hills and low mountains. Most of the uplands in the project area are mapped as mixed-grass vegetative community cover-type (a mixture of graminoids, forbs, and shrubs, with less than 25 percent of the canopy cover contributed by shrubs). Additional vegetative community cover types include Wyoming big sagebrush, irrigated cropland, dry-land crop, greasewood, and basin rock soil. Riparian areas are a mosaic of riparian shrubland on Dutton Creek and small inclusion of riparian forest along Rock Creek. A small area of saltbush community occurs along the southern boundary. No known threatened or endangered plant species or rare vegetative communities exist within the project area; therefore, the project will not contribute to cumulative degradation of these resources. Any introduction of new noxious weeds by construction truck traffic will be controlled using best management practices.

Wild animals including mule deer, whitetail deer, pronghorn antelope, coyotes, chipmunks, prairie dogs, ground squirrels, and rattlesnakes have been observed. Seasonal range maps indicate that crucial winter range of the pronghorn antelope is contained within the northeastern portion of the existing wind generation area, but not continuing into the McFadden Ridge II expansion area. See Confidential Exhibit RMP___(CAT-3-13), provided previously, for a presentation of the antelope range map. Birds including red-tailed hawks, golden eagles, bald eagles, nighthawks, sparrows and various songbirds have been observed. Migrating waterfowl, passerines, shorebirds, raptors, upland game birds, and waterbirds travel through and have been observed in the area during spring and fall migration periods. Based on avian use studies conducted, estimated bird mortality at the site would likely be similar or lower than other wind generation facility located in the western U.S. where observed bird collision mortality has been relatively low.

No federally listed wildlife or bat species were observed within the project area while spring and fall 2007 baseline avian surveys and 2008 raptor nest searches were conducted. However, the survey conducted in 2007 and spring 2008 confirmed the presence of one active bald eagle nest along Rock Creek and northwest of the project area.

Wildlife impact studies are on-going and PacifiCorp will utilize recommendations from existing U.S. Fish and Wildlife and Wyoming Game and Fish Department guidance documents to implement appropriate avoidance, minimization, and mitigation practices.

Surveys for greater sage-grouse were conducted concurrently with avian baseline surveys in 2007 and 2008. The proposed project area and a one mile buffer distance were surveyed by foot and vehicle. There are no documented greater sage-grouse leks within one mile of the project area boundary, and no leks were found during the 2007 and 2008 avian surveys of the project area. Greater sage-grouse use of the project area appears to be very low, with only two groups totaling 13 individuals being observed. The project area has been historically grazed, and there is a lack of mature sagebrush, and therefore, suitable cover for greater sage-grouse through most of the project area. Due to the low occurrence date and low flight path, greater sage-group mortality due to collisions with WTG is not likely to occur. The incremental amount of habitat lost in the project area should result in minimal impacts to the greater sage-grouse.

A project area avian constraints map is presented in previously provided Confidential Exhibit RMP___(CAT-3-14); and the avian baseline use report is presented in previously provided Confidential Exhibit RMP___(CAT-3-15).

PacifiCorp is continuing to collect bat use data within the project area.

At the end of project life, PacifiCorp will have reserved funds in its asset retirement obligation (“ARO”) account and will use ARO funding to restore the site to near natural conditions.

Lands disturbed during construction would be reclaimed to current conditions to the extent practicable. Ground disturbance would be minimized and best management practices employed by the construction contractors to minimize environmental impacts. PacifiCorp would also employ an environmental inspector(s) to ensure that environmental considerations, and any unforeseen environmental incidents, are appropriately addressed. This individual would ensure prompt and appropriate response to any identified non-compliance situations and ensure environmental protections are appropriately implemented. Periodic environmental audits of the site will also be conducted by PacifiCorp affiliated personnel that are independent of the project team.

During construction, each on-site contractor will be expected to develop, publish and orchestrate a site and project specific environmental protection plan.

Site specific wildlife management plans will be developed and implemented.

(M) A description of any potential safety hazards:

Prevention of safety hazards and impacts from failure of the project's components will be achieved by a combination of planning and controlled site access. By following industry guidelines and WTG certification processes, the most safe and reliable facility will be constructed. WTGs are equipped with multiple safety systems as standard equipment. For example, rotor speed is controlled by a redundant pitch control system and a backup disk brake system. Critical components have multiple temperature sensors and a control system to shut the system down and take it off-line if overheating conditions are detected. Lightning protection is a standard feature on the WTGs, and a specially engineered lightning protection and site grounding system will be installed for the project.

Turbine towers, WTG foundations, and above ground transmission line support structures will be designed according to applicable building codes and nationally accepted design standards to avoid failure or collapse. The selected WTG and tower combination will be subjected to engineering review to ensure that the design and construction specifications are appropriate for the project. This review will include consideration of code / nationally accepted design standard requirements under various anticipated worst case loading conditions to provide a high degree of confidence in the structural adequacy of the towers. The WTGs have been preliminarily sited at locations which exceed a reasonable set-back of over one tip-height.

During active construction, PacifiCorp will follow the manufacturers' recommended handling instructions and erection procedures to prevent material damage to towers or blades that could lead to failure. In addition, certification of the WTGs to the requirements of the *International Electrotechnical Commission ("IEC") 61400-1* standard to ensure that the static, dynamic, and defined-life fatigue stresses in the blades will not be exceeded under the combined load combinations expected at the project site. The standard includes safety factors for normal, abnormal, fatigue, and construction loads. This certification, together with regular periodic inspections, will give a high level of assurance against blade failure during operation.

The WTGs will be sited at locations that exceed a reasonable set-back distance to safeguard against ice throw. No ice throw injury has been reported from existing wind generation projects. In general, icing is an infrequent event, and the turbines for this project will be situated in a remote area.

During construction, planned construction safety controls include: (1) a "PacifiCorp Safety Plan," and (2) the EPC contractor's "Site Specific Safety Plan."

The feasibility of the project site from an aviation and airspace point of view continues to be reviewed. The WTG will be grouped in strings, and some of the WTG will include aviation warning lights, as required by the Federal Aviation Agency ("FAA"). The number of WTGs with lights and the lighting pattern of the WTG will be determined through collaboration with the FAA.

(N) A description of the real property, fuel and water requirements, including any source of water along which the major utility facility will be constructed or from which it will obtain or return water:

There are no significant fuel, minerals, or process water requirements for this project.

At the time of this filing, it is anticipated that during project construction, water will be obtained from a municipal water source; an existing senior water rights holder and trucked to the site; or a new well with a permit issued by the Wyoming State Engineer's Office to appropriate groundwater. Once available on-site, water will either be put to immediate use or placed in an on-site temporary water storage tank. Once the project is in operation, only minimal daily domestic water use will be required. The primary domestic water requirement will occur at the shared existing operations / maintenance building, and will be limited to consumption in restrooms, sinks, washing station(s), showers, internal / external hose use, and as dishwater.

A shared existing septic system and drain field for sanitary sewer waste disposal will be provided at the shared existing facilities.

(O) The acquisition status, source and location of real property, right-of-way, fuel and water requirements:

Property and right-of-way acquisition status was mentioned previously. There are no fuel acquisition requirements for this project. A groundwater use application will be applied for from the Wyoming State Engineer's Office if a new extraction well is necessary.

(P) The proposed means of transporting fuel and water requirements:

There is no process related requirement to transport material quantities of fuel and water for this project.

(Q) A description of all mineral rights associated with the facility and plans for addressing any split-estate issues:

PacifiCorp will not own any of the subsurface rights at the site. The Company does not believe that any subsurface right holder will be able to unreasonably displace the resource or any portion of the resource.

PacifiCorp has done prudent legal research on its rights as a surface lease holder, as compared to those of subsurface right holders, and is comfortable that the law does not allow subsurface right holders to unilaterally displace the Company's facilities and that any subsurface right holder would be required to enter into good faith negotiations to reasonably accommodate its subsurface extraction objective. The Company plans to approach any active minerals extraction company with operating facilities, permits secured, or planned activities to secure appropriate agreement(s), which would detail the manner in which both the Wind Project and the subject minerals activity could coexist.

(R) A statement setting forth the need for the facility in meeting present and future demands for service in Wyoming and other states:

Development of the proposed wind generation facility in compliance with regulatory requirements is the risk adjusted least cost alternative to meet service obligations in Wyoming and other states as represented in the Company's testimony and exhibits. The Company's forward looking generation planning activities are further described in the Company's 2017 IRP.

(S) A description of the commodity or service the facility will make available:

The project will generate electricity using wind as the renewable energy source. Fossil fuel consumption and waste residual disposal obligations will be avoided.

(T) A statement of the facilities effect on the applicant's and other systems' stability and reliability:

This project is not expected to adversely affect the quality, stability, and reliability of the Rocky Mountain Power ("RMP") transmission system or that of other entities. A High Plains proxy large generator interconnection "Facilities Study Report" and McFadden Ridge II status application was provided previously as Confidential Exhibit RMP___(CAT-3-16) that summarizes the expected impact.

A large generator interconnection agreement was submitted by RMP on May 18, 2017 (referencing queue position Q0863). PacifiCorp Transmission reportedly began its study sequence in October 2017, and is anticipated to deliver a "System Impact Study" in February 2018. A backfeed source is anticipated to be available to the project in June 2020 to accommodate commissioning and testing of up to two WTGs at a time.

(U) The status of satisfying local, state, Tribal or federal governmental agency requirements. The applicant shall immediately fill all agencies' final orders:

A list of the local, state, Tribal, and federal governmental agencies having requirements known at the time of this application, which PacifiCorp must meet in connection with the construction and operation of the project is listed, along with their timing and status, in previously provided Confidential Exhibit RMP___(CAT-3-17). Any unforeseen permit requirements will be adequately addressed.

By applying to and working with the various agencies for the construction / operation permits and the Commission, the major regulatory requirements and critical reviews for the project are being addressed. PacifiCorp's contractors may provide certain permits including permits for construction storm water pollution prevention control, compliance with building regulations through the Carbon County and Albany County Planning and Zoning Commissions, sanitary sewer extensions, and requirements of the Wyoming Department of Transportation. PacifiCorp will monitor and audit the successful completion, maintenance and closeout of all contractor supplied permits.

The following documents included in Exhibit RMP___(CAT-3SD) are confidential in their entirety:

Confidential Exhibit RMP (CAT 3SD-1)	McFadden Ridge II Updated WTG Site Layout

The confidential exhibits listed above are provided on CD.

REDACTED
Rocky Mountain Power
Exhibit RMP___(CAT-4SD)
Docket No. 17-035-40
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Chad A. Teply

Information and Subpart Exhibits For the Uinta Wind Energy Project

January 2018

Information and Subpart Exhibits
For the Uinta Wind Energy Project

A. Name and Address of the Applicant.

This information was provided in the application filed June 30, 2017.

B. Type of Plant, Property, or Facility Proposed to be Constructed or Acquired.

1. The Uinta Wind Project is proposed to be a commercial-scale wind energy generation system, together with all necessary appurtenances and related facilities. The size of the proposed Project is up to approximately 161 MW.

C. Description of the Facilities Proposed to be Constructed or Acquired, Including Preliminary Engineering Specifications in Sufficient Detail to Properly Describe the Principal Systems and Components, and Final and Complete Engineering Specifications When They Become Available.

2. The Uinta Wind Project is a nominally 161 MW facility that will interconnect to the Company's system at the Whitney Canyon substation, which is located within the northern part of the Project area. Development activities commenced at the Project site in 2015 immediately north of the operating Wyoming Wind Energy Center. In 2015, initial contact was made with the Project's landowners, a Large Generator Interconnection Request was filed for 120 MW, and initial consultations occurred with the United States Fish and Wildlife Service ("USFWS") and the Wyoming Game and Fish Department ("WGFD"). In 2016, the majority of the private and state land leases were signed, five meteorological towers were permitted and installed, environmental studies commenced, local stakeholder engagement began, a public open house was voluntarily conducted, and a Conditional Use Permit ("CUP") was requested from and approved by the Uinta County Commission on a 3-0 vote. In 2017, site control acquisition activities were finalized for an expanded area, environmental agency consultation continued, local stakeholder engagement continued, a second Large Generator Interconnection Request was submitted for another 101 MW, a CUP for the expanded Project area was requested from and approved by the Uinta County Commission on another 3-0 vote, and the Project was proposed and initially short-listed by the Company in its 2017R Request for Proposals ("RFP"). In 2018, the Project plans to submit an application to the Wyoming Industrial Siting Council and execute Large Generator Interconnection Agreements.

3. The Project may include all or any of the following: (i) wind energy generating systems including supporting towers, foundations, and any other associated equipment or structures (together, "Wind Turbines"); (ii) overhead and underground electrical distribution, collection, transmission and communications lines and facilities, electric transformers, electric substations, energy storage facilities, telecommunications equipment, and other necessary interconnection facilities; (iii) roads and crane pads; (iv) meteorological towers and wind measurement equipment; and (v) operations and maintenance / control building, maintenance yard(s), staging yard(s), storage area(s), and related facilities and equipment. The Project will be located in northwestern Uinta County, in southwestern Wyoming.

4. Additional Project description and information are included in Confidential Exhibit RMP___(CAT-4SD-1). Though the Applicant for this Project is the Company, the Project and all of its associated development assets are currently held by Invenergy LLC (“Invenergy”). Background information for Invenergy LLC is contained in Confidential Exhibit RMP___(CAT-4SD-7).

5. Site wind resource data is provided in Confidential Exhibit RMP___(CAT-4SD-7).

D. The Rates, if any, Proposed to be Charged for the Service that will be Rendered Because of the Proposed Construction or Acquisition.

6. The impact of the proposed facilities on the Company’s revenue requirement and the Company’s proposed ratemaking treatment is described in the testimony of Ms. Joelle R. Steward. In addition, the Company will provide service on the Transmission Projects subject to the terms and conditions of its Open Access Transmission Tariff (“OATT”).

E. The Estimated Total Cost of the Proposed Construction or Acquisition.

7. The Build-Transfer proposal submitted in October 2017 contained pricing that is summarized in Confidential Exhibit RMP__(CAT-5SD).

F. The Manner by Which the Proposed Construction or Acquisition will be Financed.

8. The Company intends to finance the proposed wind project through its normal sources of capital, both internal and external, 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 of the proposed investment will not impair the Company’s ability to continue to provide safe and reliable electricity service at reasonable rates. In addition, preapproval of the Company’s resource decision provides important regulatory support for the Company’s current credit rating. This is described in more detail in Ms. Cindy A. Crane’s testimony. The build-transfer agreement (BTA) will incorporate a milestone payment schedule to be established during negotiations between the Company and Invenergy. The rate of spend would generally be consistent with the construction schedule included in Confidential Exhibit RMP___(CAT-4SD-6).

G. Documentation of the Financial Condition of the Applicant.

9. Rocky Mountain Power’s (“RMP”) current financial condition is on file with the Commission in response to the annual reporting requirements through RMP’s semi-annual earnings reports or general rate case applications. The Company is financially capable of funding this project.

H. Estimated Annual Operating Revenues and Expenses that are Expected to Accrue from the Proposed Construction or Acquisition, including a Comparison of the Overall Effect on the Applicant’s Revenues and Expenses

10. PacifiCorp provides the economic analysis presented in Mr. Rick T. Link's testimony and exhibits, which show the revenue stream and expenses associated with the wind projects and demonstrates that the project is a risk-adjusted, least-cost alternative to serve customer loads.

I. Estimated Start and Completion Dates of the Proposed Construction or Date of Acquisition

11. If the Project moves forward as a BTA, Invenergy expects to execute EPC contracts for the Project in or around April 2018. The equipment contracts for the Project are expected to be executed in May 2019, and construction is expected to begin in April 2019.

12. The Company expects the Project to become commercially operational by December 31, 2020. Refer to Confidential Exhibit RMP___(CAT-4SD-6) for a preliminary construction schedule which supports a construction start date in 2019 and a commercial operations date in 2020.

J. Description of the Proposed Site, Including the Counties in Which the Resources will be Located, with a Metes and Bounds Description, and a Description of the Terrain where the Resources will be Constructed

13. The Project is located in northwestern Uinta County, Wyoming, within the Wyoming Basin Level III Ecoregion of southwest and central Wyoming within the Foothill Shrublands and Low Mountains Level IV Ecoregions. Confidential Exhibit RMP___(CAT-4SD-2) provides additional information on the Proposed Site. The Project area is northeast of the city of Evanston, between Wyoming Highway 89 and U.S. Highway 189. Whitney Canyon Road / Whitney Canyon Haul Road generally run through the middle of the Project area.

K. Geological Report of the Proposed Site, Including Foundation Conditions, Groundwater Conditions, Operating Mineral Deposits Within a One-Mile Radius and a Topographical Map Showing the Area Within a Five-Mile Radius

14. Information related to the geological conditions are shown in Confidential Exhibit RMP___(CAT-4SD-3).

L. Description of and Plans for Protecting the Surrounding Scenic, Historical, Archaeological and Recreational Locations; Natural Resources; Plant and Animal Life; and Land Reclamation

a. General Description of the Devices to be Installed at the Major Utility Facility to Protect Air, Water, Chemical, Biological and Thermal Qualities

b. Designed and Tested Effectiveness of Such Devices

c. Operational Conditions for Which the Devices were Designed and Tested

15. **Scenic:** Uinta County is home to the existing Wyoming Wind Energy Center and two phases of the Mountain Wind Project; residents are generally accustomed to seeing operating

turbines directly southeast of the planned Project area. The project will generally appear to be an expansion of the Wyoming Wind Energy Center. The project is not expected to be visible from the city of Evanston to the southwest. The project will be visible when driving between Evanston, WY and Woodruff, UT along State Highway 89 and when driving between Evanston and Kemmerer along US Highway 189.

16. The BLM classifies areas of visual impacts into zones 1-4, with 1 being the areas that are most sensitive to visual impacts, and 4 being the least. Though there will be no involvement of BLM lands, the Project is in a BLM-classified VRM Zone 4, classified as least sensitive to visual impacts. See Confidential Exhibit RMP___(CAT-4SD-4) for the BLM visual resource map for more detail. In addition, visual simulation surveys will be made available to the public through permitting processes to demonstrate the expected visual impacts of the facilities. The fact that the Project is adjacent to existing facilities dramatically reduces negative impacts on Wyoming's unique viewsheds by concentrating development in areas that are already affected by wind infrastructure.

17. Confidential Exhibit RMP___(CAT-4SD-4) also provides a visual rendering of the project from various perspectives and locations. In the interest of producing a conservative rendering, a larger quantity of turbines (associated with a smaller MW rating) are depicted.

18. One of the reasons the Project area was selected for wind energy development is that it contains so few residences. Another reason is that it would be adjacent to an already operating wind generating facility, which has been operating since 2003. In order to capture the wind energy that makes the Project area a good one for wind power production, the Wind Turbines generally will be located on elevated areas when possible. Wind Turbines are acknowledged to be tall structures. They will be set back from residences and non-participating property lines in accordance with setback standards approved by Uinta County in order to minimize visual impacts to residents and non-participating property owners in the vicinity. From the city of Evanston, the Project generally is not expected to be visible, because it will be blocked from view by elevated terrain that exists between the city and the Project area.

19. Wind generating facilities have been operating in Uinta County for more than 14 years in nearby locations, as shown on the map in Confidential Exhibit RMP___(CAT-4SD-4). From many areas where the proposed Project is visible, an existing wind generating facility is already visible. The Project also is not near any scenic routes or byways, as designated by the Wyoming Department of Transportation, as shown in the Scenic Areas map in Confidential Exhibit RMP___(CAT-4SD-4), nor is it near any National Parks or Wyoming State Parks, as shown in Confidential Exhibit RMP___(CAT-4SD-4).

20. **Archeological and Historical**: A contractor performed a desktop search of known cultural and archeological sites in the Project area. Beaver Creek Archeology completed a Phase I Cultural Resources Survey in February 2016 and again in January 2017 for an expanded area, utilizing Wyoming State Historic Preservation Office ("WSHPO") and National Register of Historical Places ("NRHP") records and archives over an area encompassing the Project area plus a one-mile buffer zone. The file search revealed 17 sites, no site leads, and 45 isolated finds within the Project area and a one-mile buffer. For the most part, the resources identified are not eligible for NRHP

listing. No surveys are required by the state or federal government prior to construction on private land in the Project area. The State Land parcels within the Project area will require a field survey before any ground disturbance occurs and coordination with the Wyoming Office of State Lands and Investments ("WOSLI"). The project will be designed to avoid or minimize impact to items identified in the report. Invenergy also will voluntarily conduct a pre-construction field archeological survey to identify any artifacts in the field that were not contained in the WSHPO's database. In the event items are identified, the locations of project facilities will be adjusted as appropriate. Finally, during construction, Invenergy plans to implement an Unanticipated Discoveries Plan that will give instructions to the construction crew members as to what to do in the event additional artifacts are identified during soils excavation. Essentially, work in the area will halt while the construction crew member's supervisor contacts the WSHPO to determine appropriate next steps. Invenergy intends to meet with the WSHPO to consult on the cultural, archaeological, and paleontological resources in the area and plans to send them a copy of the report described above. Communications with the WSHPO will continue thereafter. A courtesy copy also is planned to be submitted to the Uinta County Museum for review.

21. **Recreational**: The primary known recreational activities in and near the Project are hunting and fishing. Maps of the primary fishing and hunting areas are shown in Confidential Exhibit RMP___(CAT-4SD-4). A Green Ribbon fishing area is located along the southern edge of the Project area, but it is not expected to be impacted by Project construction or operations. No Blue, Red, or Yellow Ribbon fishing areas are known to occur in the Project area. According to maps produced by the Wyoming Game and Fish Department, the following are the primary big game hunting areas relative to the Project area:

- Antelope: The Project is located within the area designated as area 100 for antelope.
- Bighorn Sheep: The Project is not located within a designated Bighorn Sheep hunting area.
- Deer: The Project is located within the area designated as areas 168 and 134 for deer.
- Elk: The Project is located within the area designated as areas 105 and 106 for Elk.
- Moose: The Project is located within the areas designated as Moose hunting area 27 and 36.
- Mountain Goat: The Project is not located anywhere near designated Mountain Goat hunting areas, which are located entirely north of the Project area.

22. Invenergy is currently performing a study of aquatic resources in the Project area. Invenergy is planning to avoid the placement of facilities in or near waterways such that fish populations would be impacted; therefore, no impacts are expected. At the Dunlap wind energy facility, which has been operating since 2010 in Carbon County in eastern Wyoming, a peer-reviewed multi-year study comparing pre-construction and post-construction antelope activity indicated that there were negligible, if any, negative impacts to antelope, which is one of the primary game species in the region.

23. In their wind energy leases, the underlying landowners retain the ability to recreate and to allow others to recreate in the Project area. Except for the temporary, short-term management of certain potential safety situations during construction, impacts to the landowners' recreation rights are not expected to be impacted.

24. **Natural resources, and plant and animal life**: A comprehensive pre-construction wildlife and habitat assessment of the Project is being conducted consistent with the tiered approach of the U.S. Fish and Wildlife ("USFWS") Wind Energy Guidelines ("WEG; 2012") and the USFWS Eagle Conservation Plan Guidance (ECPG; 2013), and the Wildlife Protection Recommendations for Wind Energy Development in Wyoming ("WGFD 2010"). Per the WEG, a Tier 1 Preliminary Site Evaluation and on-site Tier 2 Site Characterization was conducted to identify native habitat, ecological communities, and other areas of broad-scale wildlife value, as well as an assessment of general wildlife habitat, areas where development may be precluded by law or due to sensitive habitat, and identification of potentially suitable habitat for state and federally-listed threatened and endangered species and species of concern within the Project area. In addition, extensive Tier 3 field studies have been conducted and are being ongoing to evaluate the temporal and spatial presence of avian and bat species and other species of concern. The environmental resources near and/or within the Project have been identified and are well understood. Invenergy continues to gather additional data to further its understanding of the area.

25. Furthermore, consultation with the USFWS and the WGFD on this Project began in 2015, before any land was leased, and will be ongoing throughout Project construction. Invenergy has worked closely with both agencies during project development to date. The methods and results of the pre-construction surveys to-date have been shared with the USFWS and the WGFD. Invenergy has met with the USFWS and WGFD regularly during the development process as shown in the Project Surveys.

26. Environmental surveys at the Project are well underway, and the critically important spring surveys are complete. Results of Invenergy's pre-construction surveys were taken into consideration in the siting of the Project turbines and infrastructure and will be incorporated into a voluntary, Project-specific Bird and Bat Conservation Strategy ("BBCS") and Eagle Conservation Plan ("ECP"). The BBCS and ECP will identify avoidance, minimization, and mitigation measures as appropriate to limit impacts to wildlife. Mitigation measures will be implemented in coordination with the USFWS and the WGFD. Further, the Project-specific BBCS and ECP are expected to include a protocol for at least one (1) year of post-construction monitoring, as well as adaptive management measures that will be implemented as necessary during operation. The Project will not construct any turbines in core sage grouse areas. There are no known Conservation Reserve Program ("CRP") properties within the Project area.

27. USFWS and WGFD have been coordinated with closely to ensure that all surveys required to support an Eagle Take Permit are being conducted in the appropriate manner, including substance and form of data recorded, should the Project decide to pursue a permit.

28. **Land reclamation:** At the end of construction, the Project will restore the areas impacted to a condition reasonably similar to their pre-construction condition. Contours will be graded so that they blend in with surrounding topography. Exposed soils will be re-seeded with a seed mix that is consistent with surrounding vegetation and is determined in consultation with the underlying landowners and the local conservation district or another similar organization. All construction debris will be removed and disposed of in a manner consistent with all relevant local, state, and federal regulations.

29. Efforts and devices to protect Air, Water, Chemical, Biological and Thermal Qualities are discussed below:

a. **Air:** The Project will have only minimal, short-term impacts on air quality during construction. The only air emissions will be from construction equipment, aggregate crushing for roads, concrete batch plants for turbine foundations, which will be permitted, and fugitive dust from driving on roads. Fugitive dust is planned to be controlled by the project. As a renewable energy generation project, the operation of the facilities will not result in emissions of greenhouse gases or other pollutants. Further, the operation of the facilities will result in long-term reduction of air pollutants that otherwise would have been emitted into the air by conventional power plants by supplanting some output from conventional power plants. As of the date of this Application, no portion of Uinta County is in a nonattainment area, as per https://www3.epa.gov/airquality/greenbook/ancl.html.

b. **Water:** Surface water resources in the Project area are shown in Confidential Exhibit RMP___(CAT-4SD-1). Drainage areas within the Project area will be designed to minimize the release of sediments into wetlands and waterways during construction, even during storm events. The design may include any of the following: erosion control blankets, silt sock, silt fence, rip rap, sedimentation ponds, covering or seeding exposed soils, and other methods as proposed by the construction contractor and approved by Invenergy. The details of the surface drainage plans will be described in a Storm Water Management Plan, which will be created prior to construction.

c. **Chemical.** All solid wastes and hazardous materials related to the construction, operation and maintenance of the Project shall be handled, stored or disposed of in accordance with the approved waste management plan and in accordance with all applicable Federal, State and County laws and regulations. Any hazardous materials or wastes that are present at the site and associated with the Project will be properly contained, and a spill response plan will be in place to ensure that, in the event of an accidental spill or leakage, there will be no contamination or transmission downstream.

d. **Biological.** Environmentally responsible wind energy development is an important part of Invenergy's and PacifiCorp's company cultures. As such, it is Invenergy's typical practice to follow the US Fish and Wildlife Service's Wind Energy Guidelines ("WEG") for land-based wind energy projects. A copy of the WEG can be found at https://www.fws.gov/ecological-services/es-library/pdfs/WEG_final.pdf. The WEG provides for a five-tiered approach for assessing biological resources at a wind project site and for avoiding, minimizing, and mitigating for impacts to sensitive wildlife and habitat. Invenergy is currently consulting with the USFWS and the WDGF and performing a series of environmental studies. Invenergy also expects to implement certain avoidance, minimization, and mitigation measures for certain species, as appropriate.

e. **Thermal qualities.** Protection measures for thermal qualities are not expected to be applicable or needed for the Project.

30. **Design and tested effectiveness of protection devices to be used.** The Project will conform to applicable industry standards, such as American National Standards Institute ("ANSI"), Institute of Electrical and Electronics Engineers ("IEEE"), and National Electrical

Safety Code ("NESC"). The Applicant will supply the applicable design certifications from the equipment manufacturers once the Wind Turbine manufacturer has been selected and the relevant documentation is available from the manufacturer. These design certifications will come from a verified company.

Development, construction, operation, maintenance, and decommissioning activities will be conducted in accordance with prudent industry practices, based on experience gained by Invenergy and the Company, as appropriate.

31. **Operational conditions under which the protection devices were designed and tested**

Development, construction, operation, maintenance, and decommissioning activities will be conducted in accordance with prudent industry practices, based on experience gained by Invenergy and the Company, as appropriate.

M. Description of Potential Safety Hazards

32. The following is a description of how potential safety hazards are planned to be addressed.

33. Wind Turbines are tall structures. The Applicant proposes to avoid and minimize safety risks to low-flying aircraft by installing aviation safety lights on the tops of most of the wind turbine nacelles, in accordance with the requirements of the Federal Aviation Administration ("FAA"). The locations of all of the wind turbines will be registered with the FAA and shown on maps used by pilots and aviators.

34. The construction and operations and maintenance personnel selected for the Project will be given site safety rules. They will be expected to participate in initial and regular follow-on safety training by qualified individuals. They will be expected to adhere to OSHA safety standards.

35. The Project will continue coordinate with local Fire, Law Enforcement, and Emergency Management personnel in order to plan and train for emergency response. A preliminary emergency response plan will be prepared and submitted to Uinta County Fire, Law Enforcement, and Emergency Management personnel for review.

36. The wind turbines are inherently unclimbable, except by way of an interior ladder, which is secured behind a locked door. There are no appurtenances on the exterior of the wind turbine that would allow a person to climb higher than a few feet off of the ground. This ensures that there will be no casualties due to falls by members of the public.

37. The private site access roads to the wind turbines and other Project facilities will be marked as "private" and will have access restricted to the public, typically by way of locking gates.

38. All high-voltage electrical equipment will be located inside of fences or enclosures and will be clearly marked as energized and dangerous.

39. Prior to construction, the Project will coordinate with all participating landowners as to prudent and safe methods of farming and ranching during the construction and operation of the Project.

40. Prior to construction, the Project will reach out to oil and gas and other mining companies in the area in order to address the placement of any wind energy facilities near any existing or proposed oil and gas or mining facilities. Initial conversations have already taken place with the primary oil and gas companies who are active in the Project area.

41. Prior to Construction, the Project will call "One Call of Wyoming" to identify any local utilities and other buried items prior to beginning excavation activities in order to ensure that all appropriate avoidance measures are taken.

42. In the design and layout of the Project, setback standards approved by Uinta County will be implemented, in addition to other setback standards that the Project believes are appropriate and prudent for the safety of underlying participating landowners, nearby non-participating landowners, nearby residents, regular occupants of the land, and general public.

N. Description of the Real Property, Fuel and Water Requirements, Including Any Source of Water Along which the Major Utility Facility will be Constructed or From Which it will Obtain or Return Water

43. The primary sources of water consumption during construction will be to make concrete and to control dust on the roads. The amount of water needed for dust control is largely dependent on weather conditions during construction and dust standards agreed to with Uinta County staff prior to construction. During operations, the only primary uses of water will be a bathroom facility at the Operations and Maintenance ("O&M") building, as well as occasional wind turbine blade cleaning and dust control, as needed. Except for fuel for construction and personal vehicles, fuel is not expected to be needed for the construction or operation of the Project.

O. Acquisition Status, Source and Location of Real Property, Right-of-Way, Fuel and Water Requirements

44. **Site Control for Real Property**. The process of negotiating for site control began in 2015, and the first wind energy lease agreements were signed in January 2016. All of the land needed is now signed under a long-term form of agreement, as detailed in Highly Confidential Exhibit RMP___(CAT-4SD-5). The recordable lease memorandum forms also are provided in Highly Confidential Exhibit RMP___(CAT-4SD-5). The Project continues to negotiate with additional landowners that are desired, though not required.

45. All of the land needed for the Project is either private or state land, with no federal or tribal land needed, and it is already secured. The total leased area is approximately 30,003 acres.

46. **Rights of Way**. The Project area is proposed to be accessed off of existing privately owned roads that are regularly used for heavy haul and industrial traffic associated with existing oil and gas facilities. Rights-of-way may be needed along these roads; this matter is currently being explored by Invenergy.

47. **Fuel**. Except for fuel for construction and personal vehicles, fuel is not expected to be needed for the construction or operation of the Project. The source and location of this fuel will be identified by the construction company and operation and maintenance staff ultimately selected to build and operate the Project. Acquisition has not yet begun.

48. **Water.** There is almost zero water consumption associated with the operation of a wind project. The primary sources of water consumption during construction will be to make concrete and to control dust on the roads. The amount of water needed for dust control is largely dependent on weather conditions during construction and dust standards agreed to with Uinta County staff prior to construction. During operations, the only primary uses of water will be a bathroom facility at the O&M building, as well as occasional wind turbine blade cleaning and dust control, as needed. The source and location of the water needed will be identified by the construction company and operation and maintenance staff ultimately selected to build and operate the Project. Acquisition has not yet begun.

P. Proposed Means of Transporting Fuel and Water Requirements

49. As for transportation of fuel and water, the only fuel requirements expected for the Project are for construction vehicles and personal vehicles for construction and operations. One or more fuel tanks are likely to be delivered to the Project site by way of a tanker truck and stored at a convenient location for construction and O&M crews, likely at a laydown yard. The delivery means for the water to the site are expected to be coordinated by the construction and O&M personnel who will be hired for the Project, but the water is likely to be delivered by way of tanker trucks.

50. The proposed facility does not require the transportation of significant amounts of fuel or water once operational.

Q. Description of All Mineral Rights Associated with the Facility and Plans for Addressing Any Split-Estate Issues

51. The Project and associated facilities are not proposed to own or use any associated mineral rights, except for surface and near-surface rock and soils to provide stability for the wind turbine foundations, and except for gravel, sand, and other aggregate materials for the construction of roads, crane pads, laydown yards, and other civil works. The use of these materials will not unreasonably impede the ability of any mineral rights owner or mineral lessee to access or extract minerals from the Project area. The Project plans to approach any active minerals extraction company with operating facilities, permits secured, or planned activities to offer a Surface Use Agreement, which would detail the manner in which both the Wind Project and the subject minerals activity could coexist in the same general area and jointly use the surface of the land. Initial discussions with one such company have already begun.

Maps from the Interactive Data Platform issued by the University of Wyoming's Enhanced Oil Recovery Institute (EORI) are available in Confidential Exhibit RMP___(CAT-4SD-3). The maps show information for any Oil and Gas Commission Permits, Conventional sites, Coal Bed sites, Injection Wells, Disposal Wells, Units, Horizontal sites, and Water Analysis are included. As shown, there extensive oil and gas infrastructure existing in the Project area. Project layouts and designs are avoiding these areas as appropriate.

R. Statement Setting Forth the Need for the Facility in Meeting Present and Future Demands for Service in Wyoming or Other States

52. The need for the general wind energy and transmission investments envisioned to meet present and future demands is described in Mr. Link's testimony.

S. Description of the Commodity or Service the Facility will Make Available

53. The Project and all of the proposed facilities will enhance the Company's ability to provide cost-effective retail electric service to customers in Wyoming, and the other five states in which the Company provides retail service.

T. Statement of the Facility's Effect on the Applicant's and Other Systems' Stability and Reliability

54. Prior to being allowed to interconnect to the grid, the Project must complete a series of interconnection studies and execute a Large Generator Interconnection Agreement ("LGIA") with PacifiCorp, which operates the transmission system in the Project area. The PacifiCorp pro forma LGIA is part of its FERC Approved Open Access Transmission Tariff ("OATT"). The studies will ensure that interconnection of the Project will not cause system reliability to fall below the applicable standards or tolerances. This is the same process required for all new commercial-scale electricity generation facilities intending to interconnect to the Company's transmission system. The interconnection studies will be performed by engineers employed or contracted by the Company, in accordance with the Company's protocols.

55. The studies include a Feasibility Study, System Impact Study, and Facilities Study. The Feasibility Study identifies the basic thermal impacts of interconnecting the Project to the grid. The System Impact Study assesses and identifies system constraints, transient instabilities, and equipment that would become over-stressed due to interconnecting the proposed generation to the transmission system. The System Impact Study includes dynamic stability and short-circuit analyses and is intended to identify new transmission system facilities required to accommodate the injection of additional power into the grid. The System Impact Study is performed in a cluster fashion, with the report addressing multiple proposed generation facilities requesting interconnection service. The Facilities Study report will be specific to the individual new generation facility, in this case the proposed Project. New generation facilities must meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and the Company's own performance, design, and reliability standards, and the facilities identified in the Facilities Study report will ensure that proper operation of the proposed generation will not diminish grid reliability outside of allowable limits.

56. The Facilities Study will provide a list of all the major equipment required in order to allow the new generation facility to safely interconnect to the transmission system, along with its required configuration. Some of this equipment will be placed at the proposed point of

interconnection, and it is possible that additional equipment will be required to be installed at other transmission facilities, outside of the transmission area of consideration, as required by project-specific or regional upgrades identified by PacifiCorp Depending on the outcome of PacifiCorp's studies and the final point of interconnection, improvements to the Shirley Basin Substation may include transformers, switches, busses, circuit breakers, relays, meters, lightning protection, fencing, ground grids, communications equipment, a control building, and other minor equipment typically associated with electrical transmission-level substations.

57. The results of PacifiCorp's studies will allow the Project to proceed to final design and micro-siting of the generation tie-line, step-up substation(s), and any improvements to the existing PacifiCorp or other transmission infrastructure. The Project's Large Generator Interconnection Request Queue numbers of #Q0715 and #Q0810 were filed in 2015 and 2016 respectively. The Project is currently in the Facilities Study and System Impact Study respectively.

U. Status of Satisfying Local, State, Tribal, or Federal Governmental Agency Requirements

58. Confidential Exhibit RMP___(CAT-4SD-8) describes the status of local, state, tribal, and federal permitting requirements and status for the wind and transmission facilities.

The following documents included in Exhibit RMP___(CAT-4SD) are confidential or highly confidential in their entirety:

Confidential Exhibit RMP (CAT 4SD-1)	Uinta Project Details and Facilities Proposed to be Constructed
Confidential Exhibit RMP (CAT 4SD-1-A)	Uinta Preliminary Site Layout
Confidential Exhibit RMP (CAT 4SD-1-D)	Uinta Preliminary One-Line Diagram
Confidential Exhibit RMP (CAT 4SD-1-E)	Uinta Wetlands and Surface Water
Confidential Exhibit RMP (CAT 4SD-2)	Uinta Site Description
Confidential Exhibit RMP (CAT 4SD-2-A)	Uinta Preliminary Metes and Bounds Description
Confidential Exhibit RMP (CAT 4SD-3)	Uinta Geology
Confidential Exhibit RMP (CAT 4SD-3-A)	Uinta Vicinity Topography
Confidential Exhibit RMP (CAT 4SD-3-B)	Uinta Groundwater
Confidential Exhibit RMP (CAT 4SD-3-C)	Uinta Surficial Geology
Confidential Exhibit RMP (CAT 4SD-3-D)	Uinta Bedrock Geology
Confidential Exhibit RMP (CAT 4SD-3-E)	Uinta Mineral Deposits
Confidential Exhibit RMP (CAT 4SD-4)	Uinta Natural Resources
Confidential Exhibit RMP (CAT 4SD-4-A)	Uinta Visual Resources Map
Confidential Exhibit RMP (CAT 4SD-4-B)	Uinta Visual Simulations
Confidential Exhibit RMP (CAT 4SD-4-C)	Uinta Regional Summary
Confidential Exhibit RMP (CAT 4SD-4-H)	Uinta Studies Status
Confidential Exhibit RMP (CAT 4SD-4-I)	Uinta Environmental Studies
Highly Confidential Exhibit RMP (CAT 4SD-5)	Uinta Property Acquisition Status
Confidential Exhibit RMP (CAT 4SD-5-B)	Landowner Map
Confidential Exhibit RMP (CAT 4SD-6)	Uinta Preliminary Construction Schedule

Confidential Exhibit RMP (CAT 4SD-7)	Uinta Site Wind Resource Data

The confidential exhibits listed above are provided on CD.

The highly confidential exhibits contain commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request. The Company requests special handling. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

REDACTED
Rocky Mountain Power
Exhibit RMP___(CAT-5SD)
Docket No. 17-035-40
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Chad A. Teply

New Wind Initial Capital Expenditure Details

January 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

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.

Rocky Mountain Power
Exhibit RMP___(RAV-1SD)
Docket No. 17-035-40
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct and Rebuttal Testimony of Rick A. Vail

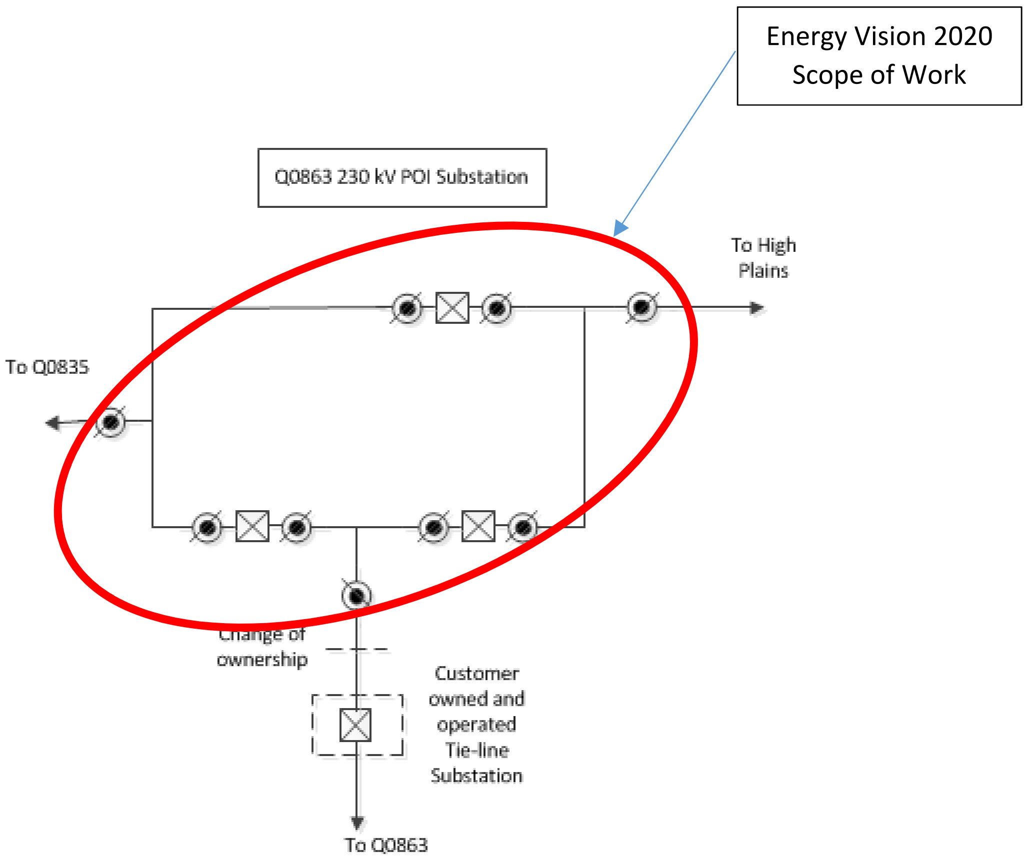
Updated Network Upgrades for RFP Results

January 2018

To support the inclusion of Q863 project the following scope of work is required in the FooteCreek area.

- Construct a new three breaker 230 kV POI ring bus substation on the High Plains – Foote Creek 230 kV line, ~2 miles southwest of High Plains substation.

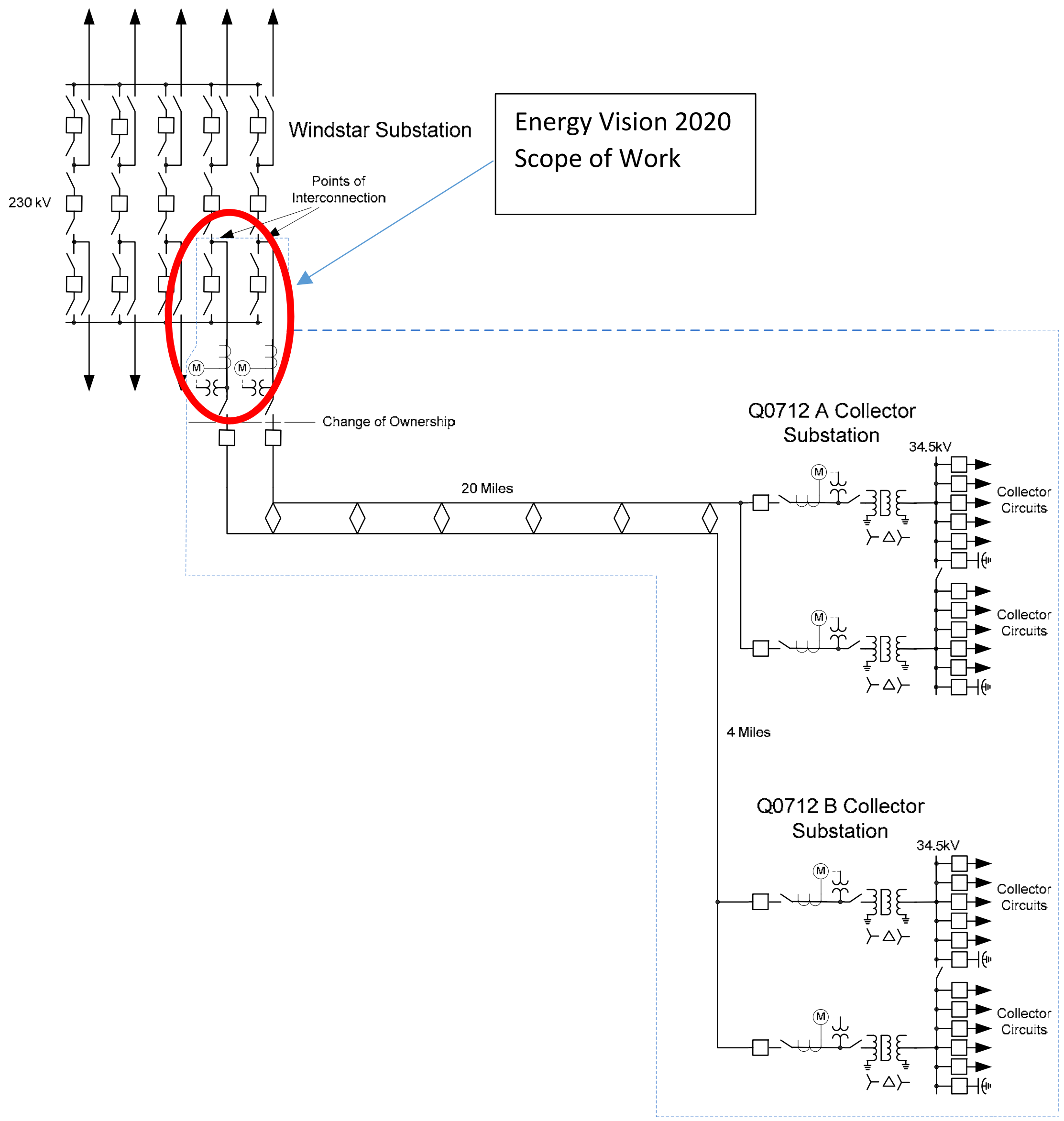
Proposed POI substation is shown below.



At the Windstar Substation, to support the inclusion of Cedar Springs 1 Wind project the following network upgrades are required.

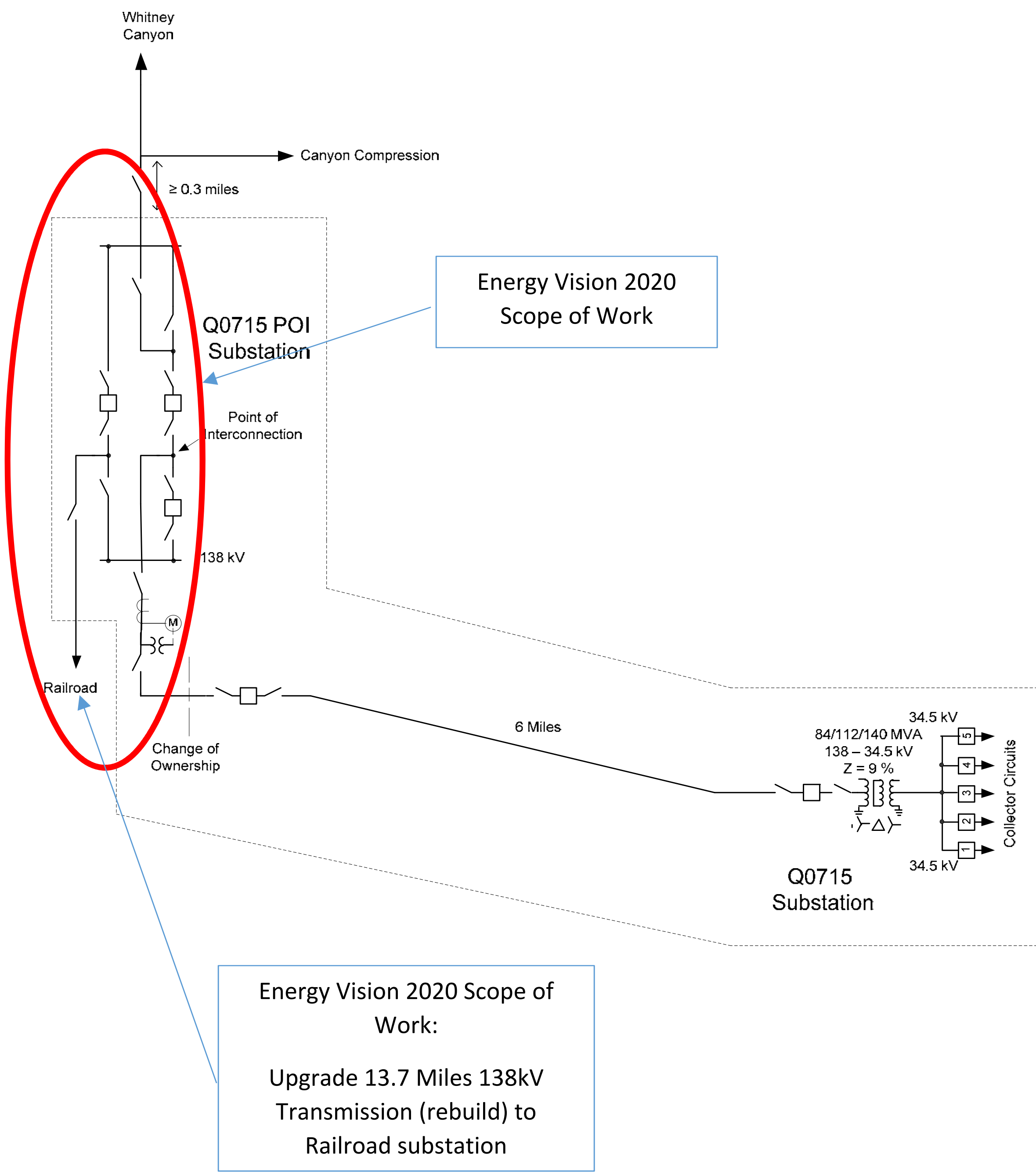
- Two (2) 230 kV 3000 ampere breakers and line positions with associated switches at Windstar substation

These are identified within the red circle.



To support the addition of Invenergy Project Q715 in the Longhollow area the following system modifications are required.

- Construct a new three breaker 138 kV POI ring bus substation southwest of the Whitney Canyon Tap (near structure 116), with associated switches and line terminations.
- Upgrade approximately 13.7 miles of the Q0715 – Railroad 138 kV line with 1-1272 ACSR/phase (line has 1-795 ACSR/phase).
- Modify the existing Naughton RAS to integrate the Q0715 project. (Redundant communication to the project is required.)



Rocky Mountain Power
Exhibit RMP___(RAV-2SD)
Docket No. 17-035-40
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
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ROCKY MOUNTAIN POWER

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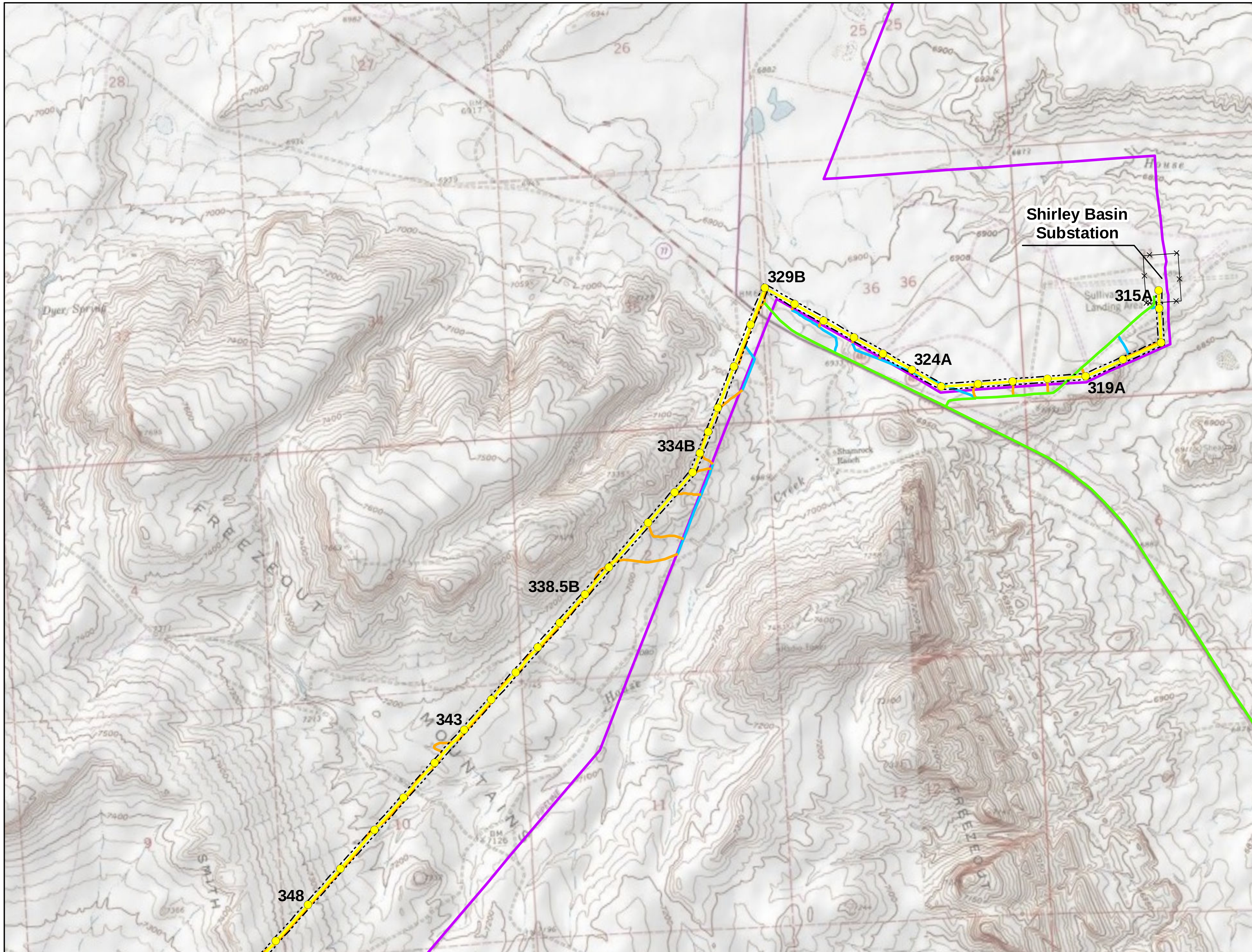
Topographical Maps for Proposed Line Route

January 2018



Legend

- Structure (Every 5th Labeled)
- Existing Freezeout-Difficulty 230kV Line
- Centerline
- ROW Edge
- Existing Road
- Improve Existing
- New Road

0 1,000 2,000 4,000 Feet

1 inch = 2,000 feet

Map Coordinate System:
NAD 1983 UTM Zone 12N

N

Difficulty to Miners 230kV Transmission Line: Partial Rebuild

Project Map Book
Page 1 of 7

drawn SGK	checked	approved	figure no.
date 1/12/2018	date	date	-
job no. 316346.00.16.A.112B.9404.0100		file no. EGW_ProjectMapBook20180112	

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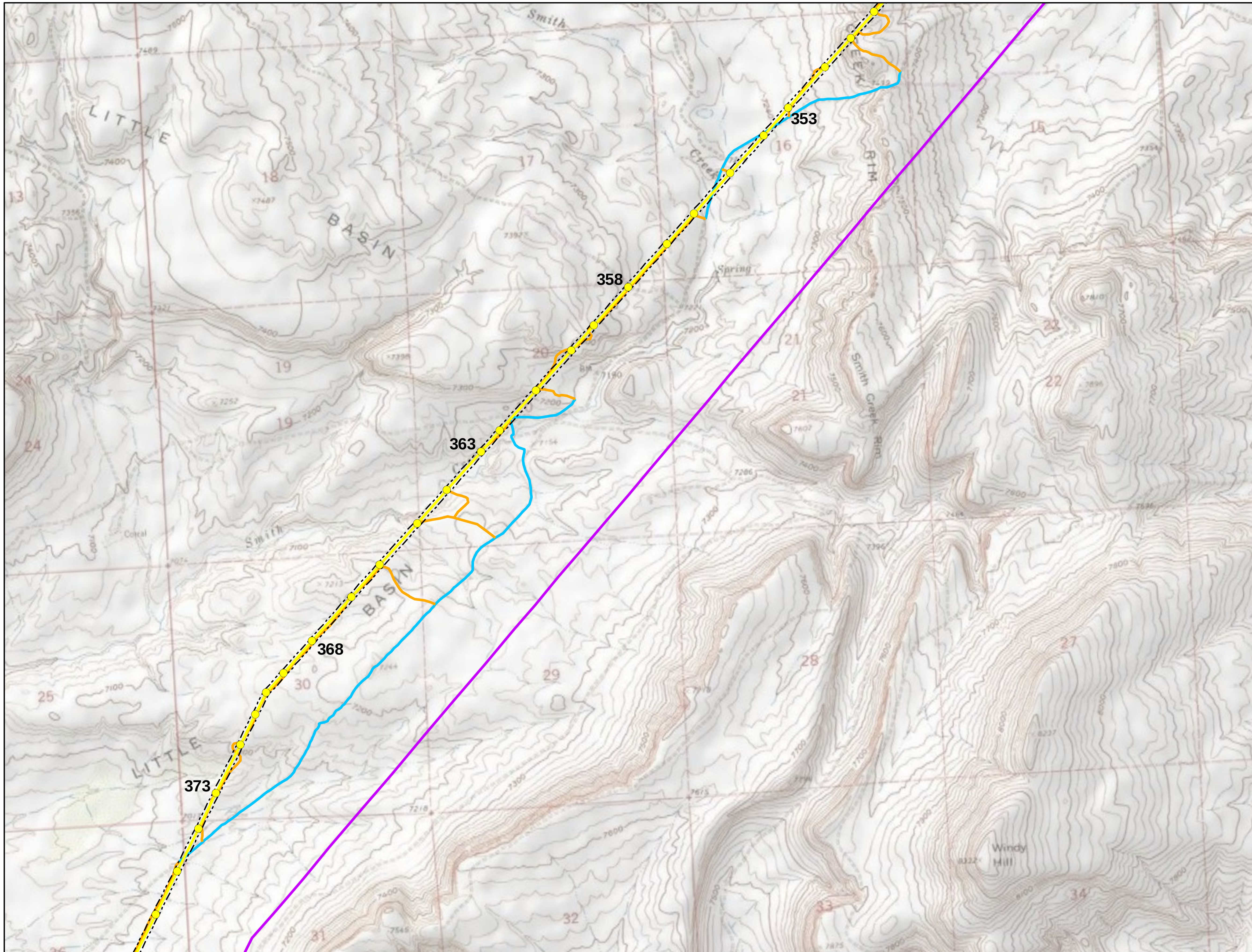

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Difficulty to Miners 230kV Transmission Line: Partial Rebuild

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Page 2 of 7

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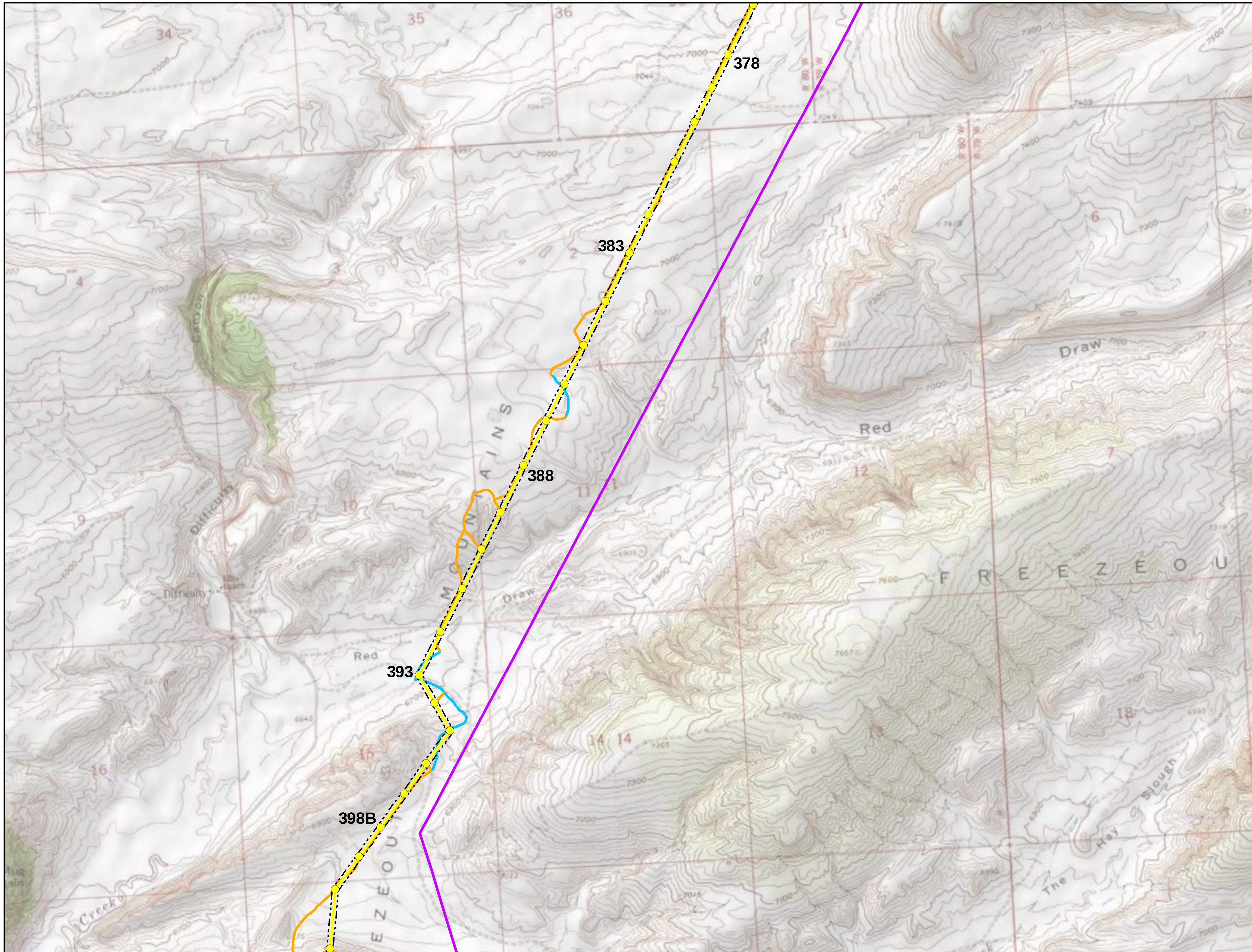

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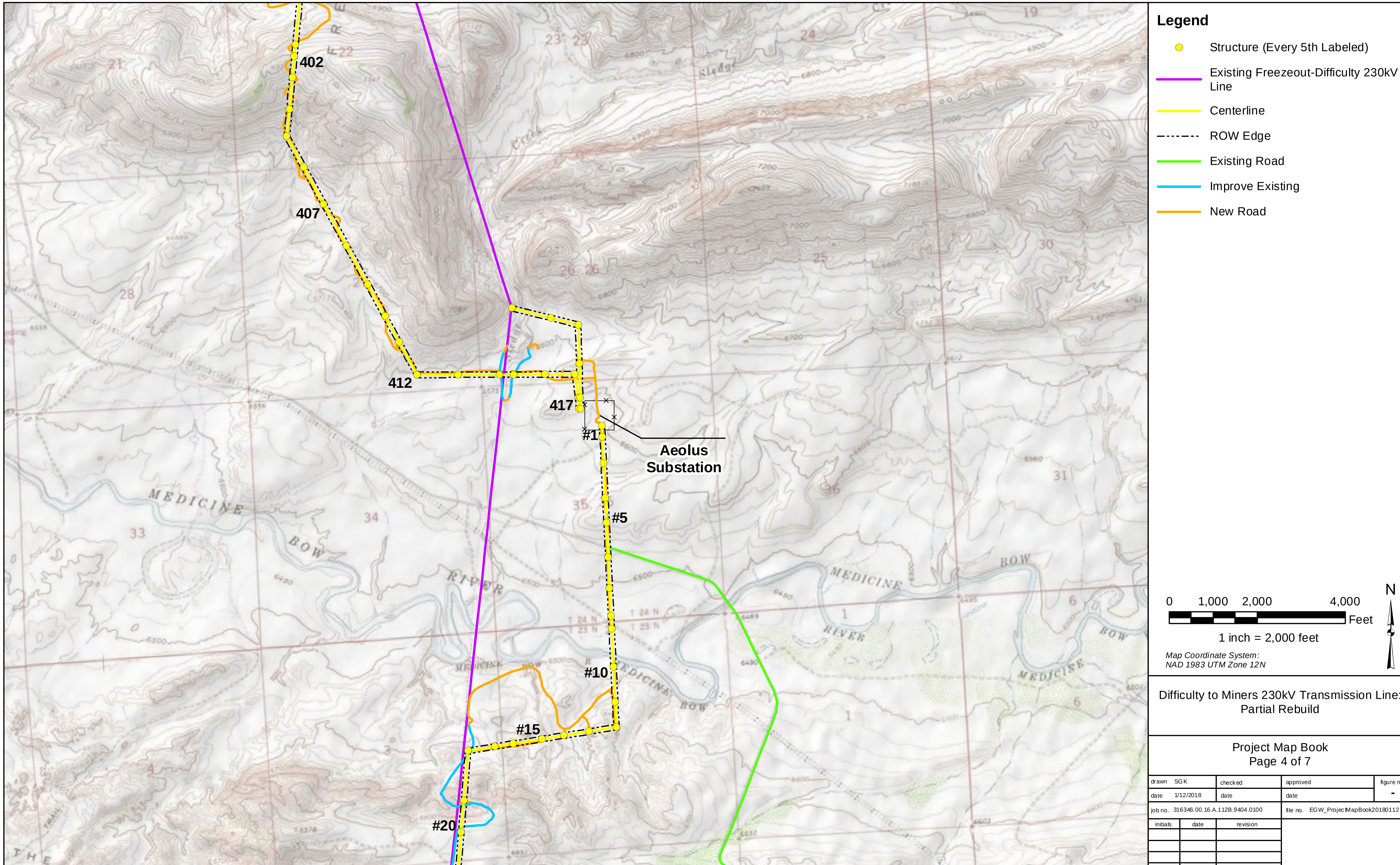

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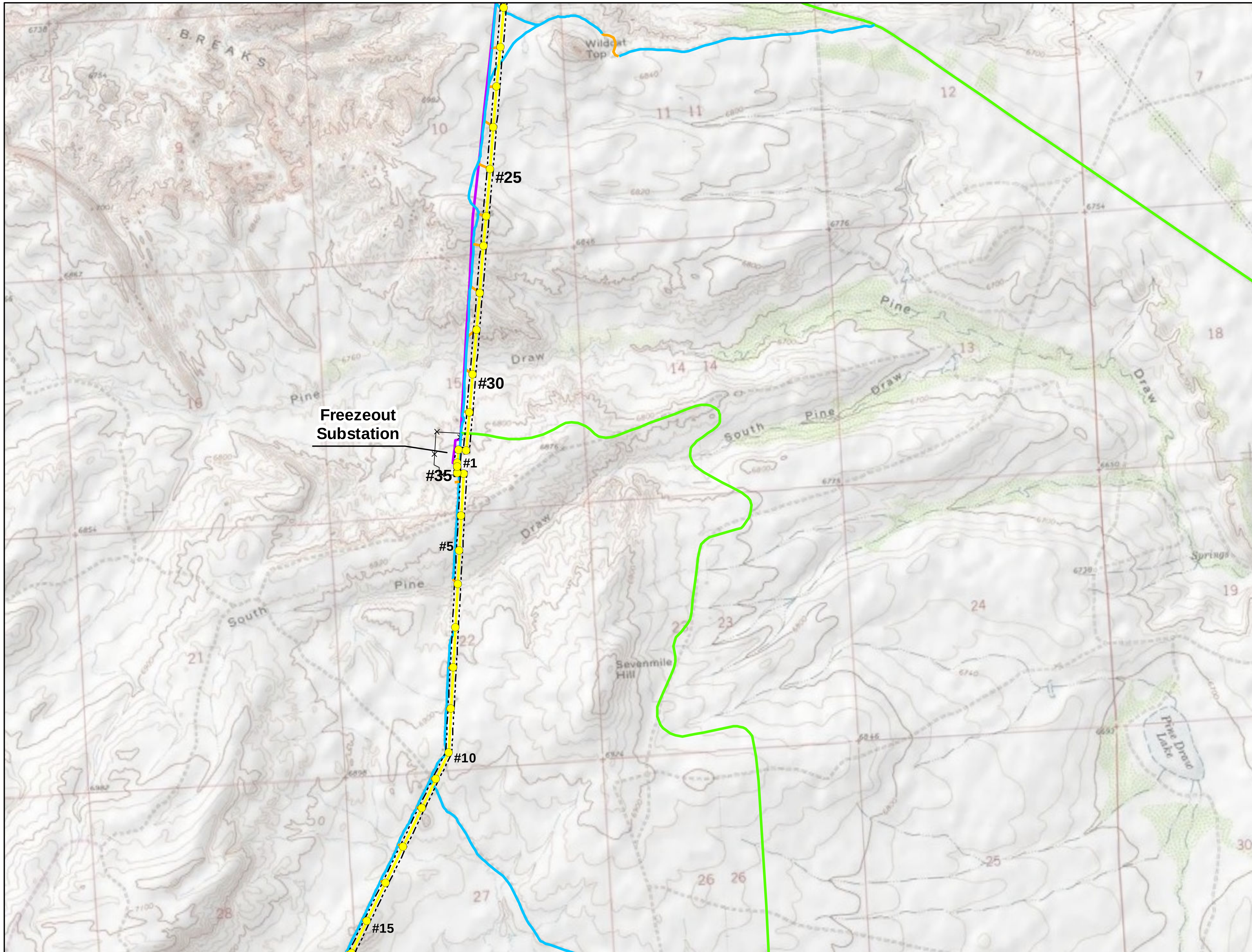

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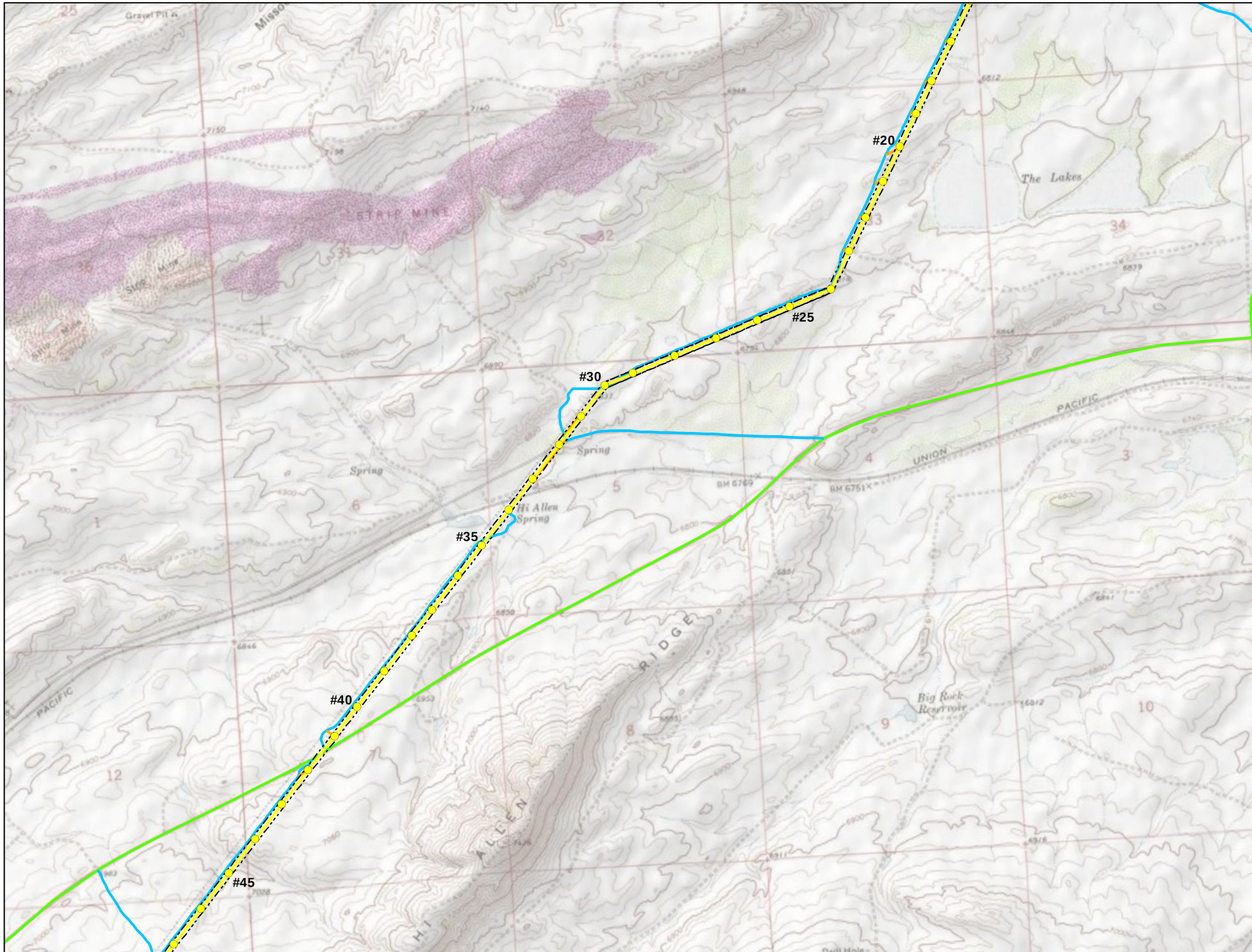

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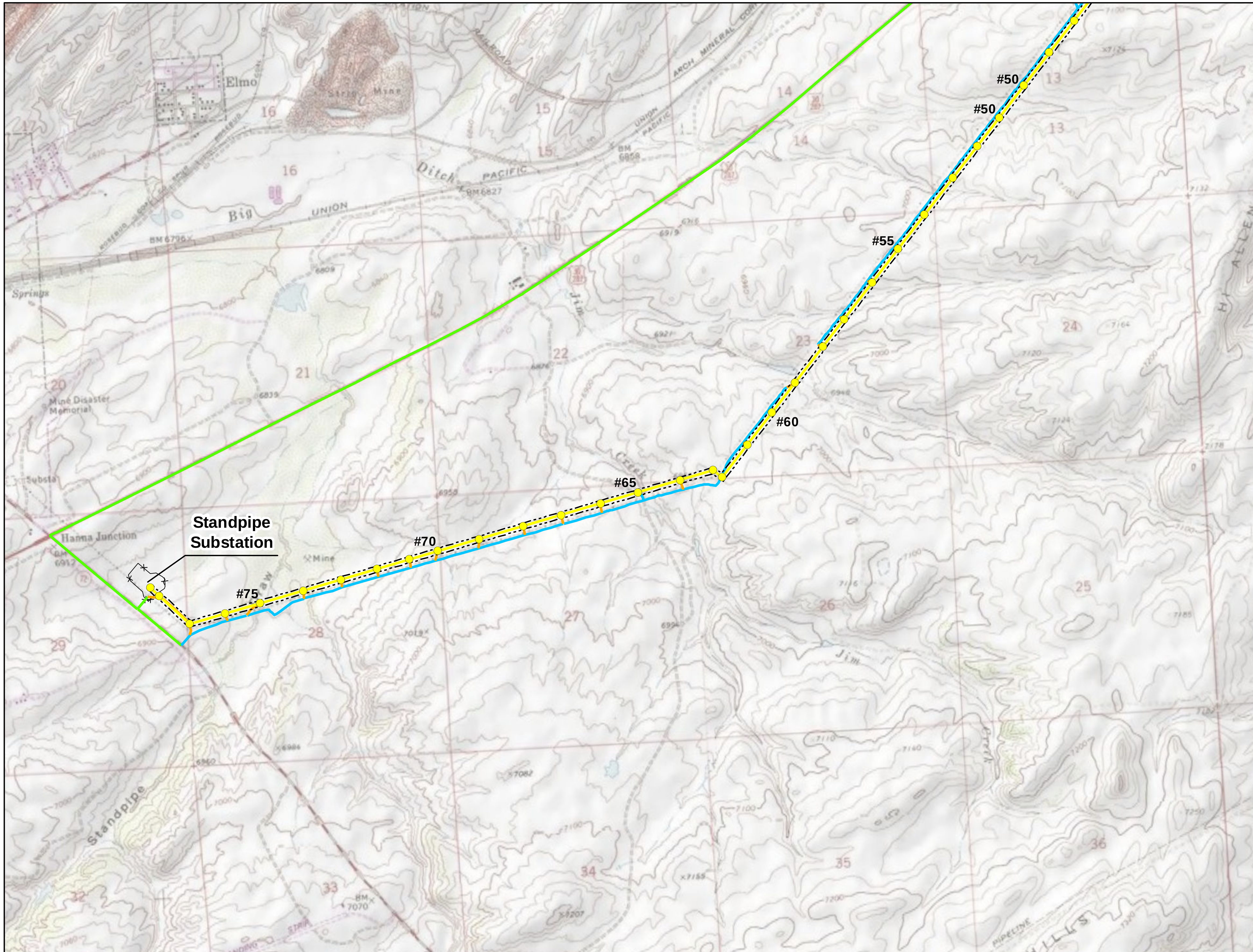

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Difficulty to Miners 230kV Transmission Line: Partial Rebuild

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Page 7 of 7

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Rocky Mountain Power
Exhibit RMP___(RAV-3SD)
Docket No. 17-035-40
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Direct and Rebuttal Testimony of Rick A. Vail

Technical Studies

January 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Rocky Mountain Power
Exhibit RMP___(RAV-4SD)
Docket No. 17-035-40
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
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ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct and Rebuttal Testimony of Rick A. Vail

Aeolus West Transmission Assessment – Preliminary Study Report

January 2018

Aeolus West Transmission Path Transfer Capability Assessment

Preliminary Study Report
Revision 1.0

October 2017

Prepared by
PacifiCorp – Transmission Planning

Table of Contents

Preliminary
Aeolus West Transmission Path
Transfer Capability Assessment

Executive Summary

This assessment was conducted to document the Transfer Capability of the Aeolus West[1] transmission path once the Gateway West – Subsegment D.2[2] (Bridger/Anticline – Aeolus) transmission facilities (D.2 Project) are added to the Wyoming transmission system.

The Aeolus West transmission path (see Figure 1) is a new path that will be formed by adding the D.2 Project in parallel with the TOT 4A[3] (Path 37) transmission path facilities. The anticipated in-service date for the D.2 Project is November 2020. The D.2 Project will include the following major transmission facilities:

- Aeolus – Anticline 500 kV new line,
- Shirley Basin – Freezeout 230 kV line loop-in to Aeolus,
- Aeolus 500/230 kV substation,
- Anticline 500/345 kV substation,
- Bridger – Anticline 345 kV new line,
- Latham dynamic voltage control device,
- Shirley Basin – Aeolus 230 kV #2 line (16-mile),
- Aeolus – Freezeout 230 kV line rebuild, and
- Freezeout – Standpipe 230 kV line reconstruction

Figure 1: Aeolus West Transmission Path

The WECC 2021-22 HW power flow base case was utilized for the Aeolus West transfer capability studies. In support of the EV2020 initiative, which calls for the addition of new and repowered wind resources in Wyoming, the base case was modified to achieve the

1 The Aeolus West path will include the following major transmission elements: Aeolus* – Anticline 500 kV, Platte* – Latham 230 kV, Mustang* – Bridger 230 kV and Riverton* – Wyopo 230 kV transmission lines. (*meter location)

2 Gateway West – Subsegment D.2 is a key component of the Energy Vision 2020 (EV2020) initiative that was announced by PacifiCorp on April 4, 2017. Other components of the EV2020 initiative include repowering PacifiCorp's existing wind fleet in southeast Wyoming and adding approximately 1,100 MW of new wind generation east of Bridger/Anticline.

3 The existing TOT 4A (Path 37) path is comprised of the Riverton* – Wyopo 230 kV, Platte – Standpipe* 230 kV and Spence* – Mustang 230 kV transmission lines. (*meter location)

transfer levels evaluated by adding 1169 MW (up 1270 MW as a sensitivity) of anticipated generation resource currently in the PacifiCorp (PAC) – Large Generation Interconnection (LGI) queue, which were used as a proxy for new resources. For different Aeolus West transfer levels (heavy and light) resources in eastern Wyoming were redispatched relative to the Jim Bridger Generation Plant.

Contingencies that were considered in this analysis include:

- N-1 of D.2 Project facilities
- N-1, N-2 Bridger contingencies
- All Wyoming transmission system contingencies performed as part of the TPL-001-4 annual assessment.

For the preliminary Transfer Capability assessment, simultaneous interaction between the Aeolus West path and the TOT 4B path was evaluated; however, the interaction with other transmission paths (Yellowtail South, Jim Bridger West, TOT 1A and TOT 3) was monitored throughout the study.

As part of the analysis, sensitivity studies were also performed to evaluate: (1) performance of different dynamic voltage control architecture (SVC vs STATCOM) at Latham, and (2) variations in the assumed magnitude and location of new wind generation, up to 1270 MW.

Conclusions

Technical studies demonstrated that with the addition of the planned D.2 Project facilities to the Wyoming transmission system, system performance will meet all NERC and WECC performance criteria.

Preliminary power flow studies demonstrate that by utilizing existing and planned southeast Wyoming resources[4], the Aeolus West transmission path can transfer up to 1696 MW under simultaneous transfer conditions with the TOT 4B transmission path, effectively[5] increasing the east to west transfer levels across Wyoming by 817.5 MW. Power flow findings also indicated:

[4] Southeast Wyoming Resources: Existing Wind: 1124 MW, Dave Johnston (net) 717 MW, Repower Wind: zero MW to 137.5 MW, New Wind: 1152 -1169 MW at various locations

[5] Effective transfers were determined by subtracting the existing TOT 4A path maximum[14] transfer level (960 MW) from the Aeolus West transfer level (1696 MW) and adding the Platte area loads (82.5 MW) that are up-stream of the Aeolus West metering point.

- Dynamic voltage control is necessary at the Latham 230 kV substation to mitigate low voltage conditions resulting from loss of Bridger/Anticline – Aeolus transmission facilities.
- Under certain operating conditions, three different Remedial Action Schemes (RAS) will need to be implemented to trip generation following outage of specific transmission facilities.
- The location (and output level) of new and repowered wind resources can influence the transfer capability level across the Aeolus West transmission path.

While a wide range of disturbances were evaluated, dynamic stability studies identified that the slowest post fault voltage recovery will occur for a fault at Anticline or Jim Bridger 345 kV bus followed by loss of the Bridger/Anticline – Aeolus transmission segment and the planned operation of a generation tripping (RAS) scheme. The stability analysis demonstrated that all planned system events met the stability performance criteria.

1 Introduction

1.1 Purpose

The purpose of this study is to identify the new Aeolus West path limitation, the interaction between the Aeolus West and the TOT 4B transmission paths by creating a nomogram, system limitation(s) and various Remedial Action Scheme (RAS), such that the interconnected transmission BES in Wyoming can support additional generation with the D.2 Project and can be operated reliably during normal and contingency operations throughout the planning horizon.

This report outlines the power flow and dynamic stability study findings from the Aeolus West transfer capability assessment and identifies performance of the BES in Wyoming with the addition of the D.2 Project and 1169 MW of new wind generation.

1.2 Plan of Service

The D.2 Project consists of the following system improvements:

1. A new 500 kV Anticline substation
2. A new 230/500 kV, 1600 MVA transformer at Aeolus
3. A new 137.8-mile 3x1272 ACSR (Bittern), 500 kV line between Aeolus and Anticline substations
4. A new 500/345 kV, 1600 MVA transformer at Anticline
5. A new 5.1-mile 3x1272 ACSR (Bittern), 345 kV line between Anticline and Jim Bridger substations
6. A new 50 MVAr reactor at Aeolus 230 kV bus
7. A new 200 MVAr shunt capacitor bank at Aeolus 500 kV bus
8. A new 200 MVAr shunt capacitor bank at Anticline 500 kV bus
9. Rebuild of the Aeolus – Freezeout and Freezeout – Standpipe 230 kV lines to 2x1272 ACSR (Bittern) conductor
10. A new 2x1557 ACSR/TW Aeolus – Shirley Basin 230 kV #2 line
11. A new dynamic reactive device at Latham 230 kV substation.

1.3 Planned Operating Date

The plan of service for the facilities to be operational is by November 2020.

1.4 Scope

The Aeolus West transfer capability assessment assumes the addition of new wind generation facilities plus the repowered wind generation modeling data as noted in Table 1. While the new technology and model information of the repowered units was used in the steady-state and transient stability analysis, no incremental MW output was considered; i.e., each repowered facility was limited to its current Large Generator Interconnection (LGI) agreement capacity. The study was performed using a 2021-22 heavy winter WECC approved case which was modified to include the D.2 Projects and wind generation facilities. The system model assumed summer line ratings to assess the thermal limitation of the Wyoming system. Load served from Platte is normally represented as an open point between Platte – Whiskey Peak 115 kV. The system configuration with Platte 115 kV normally open is presently the most limiting scenario for the existing TOT 4A/4B nomogram.

Table 1: Generating Resource Scenario

East Wyoming Thermal Gen (MW)	Jim Bridger Gen level (MW)	East Wyoming Existing Wind (MW)	Repowered Wind (MW)	New SE Wyoming. Wind (MW)
Dave Johnston – Online Wyodak - Online	1400 – 2100	1124 (Foote Creek, Rock River, High Plains, Seven Mile Hill, Dunlap, Root Creek, Top of the World, Glenrock, Three Buttes, Chevron)	0.0 Repowering wind turbine representation was added to the system model but the output was limited to existing LGI levels	1169 See Table 4

2 Study Criteria

2.1 Thermal Loading

For system normal conditions described by the P0[6] event, thermal loading on BES transmission lines and transformers is required to be within continuous ratings.

[6] Facility outage events that are identified with "P" designations are referenced to the TPL-001-4 NERC standard.

For contingency conditions described by P1-P7 category planning events, thermal loading on transmission lines and transformers should remain within 30-minute emergency ratings.

The thermal ratings of PacifiCorp's BES transmission lines and transformers are based on PacifiCorp's Weak Link Transmission Database and Weak Link Transformer Database as of March 31, 2017.

2.2 Steady State Voltage Range

The steady state voltage ranges at all PacifiCorp BES buses shall be within acceptable limits as established in PacifiCorp's Engineering Handbook section 1B.3 "Planning Standards for Transmission Voltage[7]" as shown below.

Table 2: Voltage Criteria

Operating System Configuration	Normal Conditions (P0)		Contingency Conditions (P1-P7)	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)
Looped	0.95	1.06[8]	0.90	1.10
Radial	0.90	1.06[8]	0.85	1.10

Steady state voltage ranges at all applicable BES buses on adjacent systems were screened based on the limits established by WECC regional criterion as follows:

- 95% to 105% of nominal for P0 event (system normal),
- 90% to 110% of nominal for P1-P7 events (contingency).

2.3 Post-Transient Voltage Deviation

Post-contingency steady state voltage deviation at each applicable BES load serving bus (having no intermediate connection) shall not exceed 8% for P1 events.

2.4 Transient Stability Analysis Criteria

All voltages, frequencies and relative rotor angles are required to be stable and damped. Cascading or uncontrolled separation shall not occur and transient voltage response shall be within established limits.

[7] PacifiCorp Engineering Handbook "Planning Standards for Transmission Voltage," April 8, 2013.

[8] In some situations, voltages may go as high as 1.08 pu at non-load buses, contingent upon equipment rating review.

2.5 Transient Voltage Response

Transient stability voltage response criteria are based on WECC Regional Performance Criteria WR1.3 through WR1.5 as follows:

- Transient stability voltage response at the applicable BES buses serving load (having no intermediate connection) shall recover to at least 80% of pre-contingency voltage within 20 seconds of the initiating event for all P1-P7 category events, for each applicable bus serving load.
- For voltage swings following fault clearing and voltage recovery above 80%, voltage dips at each applicable BES bus serving load (having no intermediate buses) shall not dip below 70% of pre-contingency voltage for more than 30 cycles or remain below 80% of pre-contingency voltage for more than two seconds for all P1-P7 category events.
- For contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load (having no intermediate buses) shall not dip below 70% of pre-contingency voltage for more than 30 cycles or remain below 80% of pre-contingency voltage for more than two seconds.

The following criteria were used to investigate the potential for cascading and uncontrolled islanding:

- Load interruption due to successive line tripping for thermal violations shall be confined to the immediate impacted areas and shall not propagate to other areas. The highest available emergency rating is used to determine the tripping threshold for lines or transformers when evaluating a scenario that may lead to cascading.
- Voltage deficiencies caused by either the initiating event or successive line tripping shall be confined to the immediate impacted areas, and shall not propagate to other areas.

Positive damping in stability analysis is demonstrated by showing that the amplitude of power angle or voltage magnitude oscillations after a minimum of 10 seconds is less than the initial post-contingency amplitude. Oscillations that do not show positive damping within a 30-second time frame shall be deemed unacceptable.

Stability studies shall be performed for planning events to determine whether the BES meets the performance requirements.

- Single contingencies (P1 category events): No generating unit shall pull out of synchronism (excludes generators being disconnected from the system by fault clearing action or by a special protection system).
- Multiple contingencies (P2-P7 category events): When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any transmission system elements other than the generating unit and its directly connected facilities.
- Power oscillations are evaluated by exhibiting acceptable damping. The absence of positive damping within a 30-second time frame is considered un-damped.

3 Base Case Development

3.1 Base Case Selection

The base case development process involves selecting an approved WECC base case, updating the models to represent existing and planned facilities (D.2 Project transmission and wind generation facilities) and then tuning the cases to maximum transfer conditions on the WECC transmission path(s) being studied. For this study purpose, the published WECC base case that is close to the projects' in-service date of November 2020, which has average load conditions based on 2021 load projection and availability of a stability case, was selected. The WECC approved base case 2021-22 HW (created on August 19, 2016) was selected, which meets these criteria. This study focused on simultaneous transmission path interaction in the Wyoming area between the Aeolus West and the TOT 4B transmission paths; however, other transmission paths such as Yellowtail South (non-WECC path), Jim Bridger West, TOT 1A and TOT 3 (See Appendix A for path definitions) were monitored throughout the study.

The various critical components for this study purpose from selected 2021-22 HW base case are listed below:

Table 3: Wyoming Load, Generation and Platte Normal Open Configuration in Base Case

North Wyoming PAC Load (including Wyodak load of 42 MW)	391 MW
North Wyoming - Western Area Power Administration (WAPA) Load	211 MW
Eastern Wyoming PAC Load (including DJ load of 56 MW)	474 MW
Eastern Wyoming PAC loads on WAPA system	95 MW

Central Wyoming Load (including JB load of 130 MW)	434 MW
Yellowtail South Flow	192 MW
Yellowtail Generation	140/260 MW (Online/Max)
WAPA's Existing Small Generation[9] in North Wyoming	26/50 MW(Online/Max)
WAPA's Existing Small Generation[10] in Eastern Wyoming	484/584 MW(Online/Max)
Wyodak Generation (PacifiCorp/Black Hills)	350/380 MW (Online/Max)
Dry Fork Generation (Basin Electric)	420/440 MW (Online/Max)
Gross Laramie River Generation I (WAPA's swing machine)	605 MW(Max)
Gross Laramie River Generation II	590/605 MW(Online/Max)
Gross Dave Johnston (DJ) Generation	700/774 MW(Online/Max)
Total Existing PAC East Wyoming Wind[11] Generation	885.7/1124 MW (Online/Max)
Rapid City DC W Tie	130 W2E (200 MW-bidirectional)
Stegall DC Tie	100 E2W (110 MW-bidirectional)
Sydney DC Tie	196 E2W (200 MW-bidirectional)
TOT 4A	627 MW
TOT 4B	469 MW
Jim Bridger (JB) Generation	2200 MW
Jim Bridger West Flow	2027 MW
TOT 3	1259.1 MW
TOT 1A	195 MW
Platte – Mustang 115 kV Normal Open point	Platte – Normal Open

[9] WAPA's small generation in north Wyoming includes; Boysen, BBill, Heart MT, Shoshone, Spring Mtn

[10] WAPA's small generation in eastern Wyoming includes; Alcova, Fremont, Glendo, Guernsy, Kortes, Seminoe, CLR_1, SS_Gen1 AND CPGSTN

[11] PAC eastern Wyoming wind generation includes; Root Creek, Three Buttes, Top of World, Glenrock, Rolling Hills, Dunlap. Seven Mile Hill, Foote Creek and High Plains wind generation

3.2 Generating Facility Additions

Because the specific size and location of new and repowered Wyoming wind generation associated with the EV2020 initiative will not be known until 1Q18, this study evaluated anticipated Wyoming wind generation options[12] for the preliminary Aeolus West analysis, based on requests in the PacifiCorp Large Generation Interconnection (LGI) queue as a proxy for new resources. The following generating facility assumptions were made and added into the base case.

Table 4: Assumed Generation Projects

Proposed New Wind Facilities	Project size	Point of Interconnection
Aeolus/Freezeout/Shirley Basin Area	320 MW	Freezeout 230 kV
	250 MW	Aeolus 230 kV
	250 MW	Shirley Basin 230 kV
	250 MW	Shirley Basin 230 kV
Foote Creek Area	99 MW	Foote Creek – High Plains 230 kV line 230 kV
Repowered Wind Facilities[13]		
High Plains/McFadden Ridge I Gen Repowering (+29.75 MW)	0.0 MW	High Plains 230 kV
Seven Mile Hill Gen Repowering (+27.65 MW)	0.0 MW	Freezeout 230 kV
Dunlap Gen Repowering (+26 MW)	0.0 MW	Shirley Basin 230 kV
Glenrock Gen Repowering I (+27.65)	0.0 MW	Windstar 230 kV
Glenrock Gen Repowering II (+27.65 MW)	0.0 MW	Windstar 230 kV
TOTAL	**1169 MW**	

See Appendix B for detail on repowered and new wind farm modelling assumptions.

[12] An additional resource option is outline in Sensitivity Study - Section 5.B.

[13] The repowered generation was modeled, but the repowered MW output was not increased in the base case, i.e. increase machine size was modeled, but output was limited to existing LGI agreement

3.3 Base Case Modification and Tuning

The 2021-22HW base case was modified to reflect the most recent Foote Creek, High Plains, Top of the World and Three Buttes wind generation modeling as per recent MOD-032 data submitted by each generator owner (GO). Transmission line impedances between Dave Johnston and Standpipe were verified and updated and the transmission line ratings in the 2021-22 heavy winter case were modified to summer ratings, which represent the most conservative thermal limitations. The Platte – Standpipe 230 kV dynamic line rating of 608/666/680 MVA was assumed during the analysis.

The new wind resources listed in Table 4 were added to the base case and the existing repowered wind farm generator models and collector system data were updated. The Aeolus West path was stressed by maximizing the output on all of the existing and new wind generation facilities. Output for the repowered wind generation facilities was limited to the existing LGI agreement generation levels. The additional generation in southeast Wyoming was re-dispatched with Jim Bridger, central and southern Utah generation. The Jim Bridger generation output was maintained such that Jim Bridger West path flows were held at 2400 MW.

As per the available data obtained from various wind generation facilities at the time of this study analysis, the base cases were reviewed and adjusted to ensure voltages in the collector system of wind generation facilities were below 1.05 p.u. and that there was no reactive power loop flow between the main generator step-up transformers GSU’s for wind generation facility. This process involved tuning transformer and generator parameters such that generators were producing appropriate reactive power output. Additionally, within the 230 kV transmission system it was verified that the shunt reactive devices were accurately represented, voltage profiles were normal, reactive power flows were within normal operating ranges and transmission system voltage was maintained to match acceptable PacifiCorp Transmission Voltage Schedules.

4 Path Studies

4.1 Aeolus West vs. TOT 4B

Based on the assumptions outlined above the study demonstrated that the Aeolus West maximum transfer capability limit is 1696 MW, while meeting all NERC and WECC performance criteria. While this transfer level is 735 MW above the present TOT 4A (960

MW[14]) path limit for similar conditions, east to west transfers have effectively increased by 817.5 MW due to shifting the Platte area load (82.5 MW) east of the Aeolus West cut plane. The Aeolus West path was stressed using by 3010 MW of total generation resources, which includes thermal (Dave Johnston, 717 MW - net), existing wind (1124 MW), and new wind (1169 MW) resources. It was assumed that the following eastern Wyoming thermal generation was available for redispatch to maintain transfers on the Aeolus West and the TOT 4B transmission paths:

- Wyodak (268 MW)
- Dave Johnston (717 MW, net)

The maximum flow limitation of 1696 MW was achieved by utilizing all new and existing wind resources and reducing Dave Johnston generation by 149 MW.

Table 5: Aeolus West and TOT 4B Corner Point Cases (See Figure 2)

Case	TOT 4A (MW)	TOT 4B (MW)	Platte – Latham (MVA)	Limiting Element	Outage
1	1696	103	546	Platte- Latham 230 kV line[15]	Anticline – Aeolus 500 kV line outage with RAS
2	1681	299	548	Platte- Latham 230 kV line[15]	Anticline – Aeolus 500 kV line outage with RAS
3	1651	499	547	Platte- Latham 230 kV line[15]	Anticline – Aeolus 500 kV line outage with RAS
4	1608	700	547	Platte- Latham 230 kV line[15]	Anticline – Aeolus 500 kV line outage with RAS
5	1575	857	-	Yellowtail – Sheridan 230 kV line	N-0
			547	Platte- Latham 230 kV line[15]	Anticline – Aeolus 500 kV line outage with RAS

[14] Maximum nomogram point with normal open point at Platte and the dynamic line rating on Platte – Standpipe 230 kV line is utilized

[15] Platte – Latham 230 kV line flow may exceed the 557 MVA summer emergency rating depending on load at Platte. Percentage loading is based on current rather than MVA.

See Appendix C for power flow diagrams.

In the study, three different remedial action schemes (RAS) were considered for N-1 outages:

i. Aeolus RAS to trip up to 640 MW of wind generation depending on pre-outage flow conditions for any of the new transmission element outages between Aeolus – Jim Bridger.

ii. Freezeout RAS to trip up to 140 MW of generation in the Freezeout area for the Aeolus – Freezeout 230 kV line outage depending on the pre-outage flow conditions.

iii. Shirley Basin RAS to trip up to 60 MW of generation in the Shirley Basin area for the Aeolus – Shirley Basin 230 kV line outage depending on pre-outage flow conditions.

Figure 2: Aeolus West Vs TOT 4B Nomogram

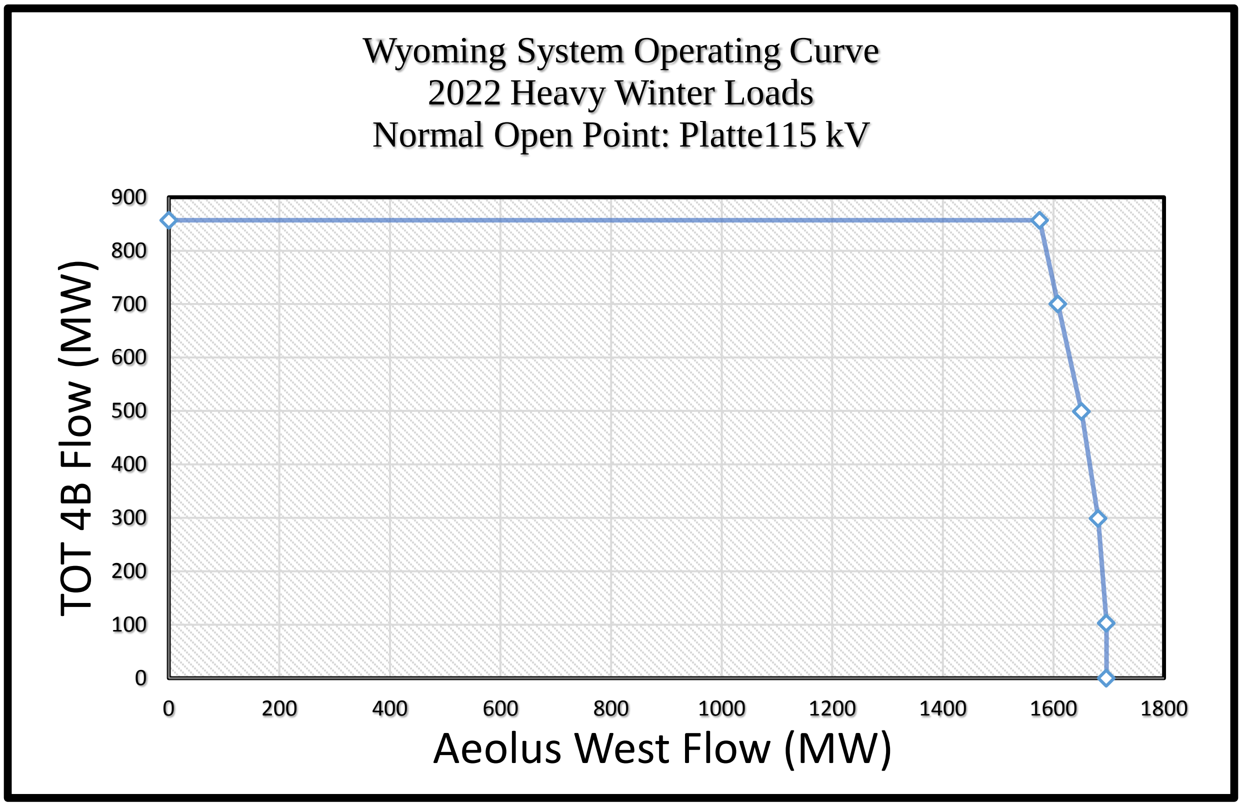


Figure 2 depicts that the Aeolus West and TOT 4B path interaction is minimized with the addition of the D.2 Project, as indicated by the steeper curve (implying little or no path interaction) as compared to present TOT 4A/TOT 4B interaction. However, anytime the emergency dynamic line rating on Platte – Standpipe is lower than 651 MVA[16] the nomogram in Figure 2 will be shifted to the left. Therefore, a new system operating limit (SOL) value will be identified to represent the real time rating restriction to the path. Additionally, the load at Platte substation can cause a shift in the nomogram; higher load at Platte can shift the curve towards the right and lower load at Platte can shift the curve towards the left, making it more conservative. This is due to the Platte – Latham 230 kV line being the limiting element, as mentioned in Table 5.

4.2 Base Case Development

The 2021-22 HW WECC case was modified to simultaneously stress the Aeolus West and the TOT 4B path flows. The Aeolus West path was stressed using approximately 2861 MW of eastern Wyoming resource from a total of 3010 MW (existing and future) wind and net coal resource. These resources were re-dispatched with Jim Bridger and Utah Valley resources such that the Jim Bridger West flows were maintained at 2400 MW. No additional resources were imported from WAPA into PAC to stress the Aeolus West path. Since the future resources in eastern Wyoming are in excess of future available transmission capacity, Dave Johnston plant output was reduced in eastern Wyoming. The Shiprock, San Juan and Gladstone phase shifters were locked to regulate flow across the TOT 3 path between Colorado and Wyoming.

The TOT 4B path flows were adjusted between a minimum of 100 MW and a maximum of 857 MW. The Montana resources, up to 388 MW, were re-dispatched with WAPA (Dry Fork) to reduce TOT 4B flow or re-dispatched with PAC resources to increase the TOT 4B flow using Crossover, Rimrock and Steam Plant phase shifters in Montana.

4.3 Transient Stability Analysis

The stability analysis was performed using GE provided model (GE0501) for repowered and new wind generation. The generic model for the Root Creek wind model was updated to GE0501 (GE 1.85 units). Top of the World and Three Buttes were updated to GE 1.5 wind turbine model provided by GE for PTI V33. The generic WECC models were used for the Latham dynamic reactive device.

The transient stability study was performed for one (worst case) nomogram point of the Aeolus West vs. the TOT 4B nomogram curve. The nomogram point with the heaviest

[16] The highest loading on the Platte – Standpipe 230 kV line as per power flow analysis based on study assumption.

Aeolus West flow was considered for stability study analysis. Table 6 provides the nomogram point description.

Table 6: Nomogram point for Dynamic Stability

Case	TOT 4A (MW)	TOT 4B (MW)	Platte – Latham (MVA)	Limiting Element	Outage
1	1696	103	546	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS

See Appendix D for dynamic stability plots

Transient stability was performed on selective critical outages based on anticipated post fault impact on the wind generation performance, especially for the portion of the system with a calculated short circuit ratio of approximately 1.5. Below is the list of critical transmission outages.

1. Point of Rocks – Latham 230 kV line outage for three phase fault at Latham 230 kV bus (5 cycles)
2. Standpipe – Platte 230 kV line outage for three phase fault at Standpipe 230 kV bus (5 cycles)
3. Platte – Latham 230 kV line outage for three phase fault at Platte 230 kV bus (5 cycles)
4. Dave Johnston – Casper 230 kV line outage for three phase fault at Dave Johnston 230 V bus (5 cycles)
5. Amasa – Difficulty 230 kV line outage for three phase fault at Amasa 230 kV bus (5 cycles)
6. Dave Johnston – Amasa 230 kV line outage for three phase fault at Dave Johnston 230 kV bus (5 cycles)
7. Shirley Basin – Aeolus 230 kV line outage for three phase fault at Shirley Basin 230 kV bus (5 cycles)
8. Freezeout – Standpipe 230 kV line outage for three phase fault at Freezeout 230 kV bus (5 cycles)

9. Aeolus – Freezeout 230 kV line outage for three phase fault at Aeolus 230 kV bus (5 cycles)
10. Aeolus – Anticline 500 kV line outage for three phase fault at Aeolus 230 kV bus (4 cycle fault and 10 cycles for RAS operation)
11. Aeolus – Anticline 500 kV line outage for three phase fault at Anticline 345 kV bus (4 cycle fault and 10 cycles for RAS operation)
12. Riverton – Wyopo 230 kV line outage for three phase fault at Riverton 230 kV bus (5 cycles)

Observation 1: During the stability analysis it was identified that the Latham SVC model tripped on high voltage for Platte – Standpipe 230 kV line outage. Following the fault, the Latham SVC is radial from Point of Rocks substation, causing high voltage at Latham 230 kV bus and tripping the SVC model. This issue can be resolved with changing the SVC operating parameter such that the SVC blocks VAR supply for voltage below a certain voltage level.

Observation 2: Additionally the slowest voltage recovery following the fault clearing occurs for a fault at either the Anticline or the Jim Bridger 345 kV bus followed by the loss of the new Aeolus – Anticline/Jim Bridger segment and operation of the Aeolus RAS to drop generation, causing the largest angular separation between Jim Bridger and Dave Johnston. For local fault conditions, the GE wind turbine models ramp down momentarily, whereas the models do not ramp for remote faults.

Due to the fault being on the remote end (at Anticline or Jim Bridger) of the new Aeolus – Bridger line segment, which is isolated from the wind farms, the voltage depression seen by the wind generating units (modelled as current source) are not as low, the power output is much higher during the fault and power output recovery is much faster after the fault as compared to the fault close to Aeolus. The remote fault results in more stress on the system during the fault and post fault, which leads to slower voltage recovery. The synchronous machines (modelled as voltage source) at Dave Johnston and Jim Bridger (one unit offline in the stress base case) try to recover the system voltage, which leads to higher angular separation between the two buses. Thus, the loss of the Aeolus – Anticline/Jim Bridger segment with a remote fault is the most severe.

This issue can be mitigated by effectively sizing dynamic reactive device at Latham to boost the system voltage. This disturbance did not result in system instability or system separation.

Additionally, the stability analysis demonstrated that all planning events met stability performance criteria.

5 Sensitivity Analysis

A. A sensitivity study was performed to replace the SVC dynamic device model at Latham with a generic STATCOM model. The dynamic simulations were performed for a stressed base case and the STATCOM model displayed behavior similar to the SVC model. High post fault voltage conditions require model data adjustments to prevent SVC and STATCOM model blocking and tripping.

B. A sensitivity analysis was performed to evaluate the system impacts of increasing the magnitude and changing the location of generation resources identified in the Assumed Generation Projects in Table 4. As part of this analysis, assumed wind generation was increased from 1169 MW to 1270 MW, by increasing the repowered generation by 137.5 MW and adding 240 MW of new generation in the Bighorn area of northern Wyoming, and reducing the new wind generation at Shirley Basin from 500 MW to 250 MW. (Other generation adjustments were made for loads and resource balancing.) Due to reduced generation in southeast Wyoming, Aeolus West transfer capability limit increased to 1790 MW. The limiting element was the Platte – Latham 230 kV line emergency thermal rating following outage of the Bridger/Anticline – Aeolus facilities and initiation of associated generating tripping.

   The study also identified two different RAS schemes to trip generation for N-1 outage:

   i. Aeolus RAS to trip up to 640 MW of wind generation depending on pre outage flow conditions for any of the new transmission element outage between Aeolus – Anticline/Jim Bridger segment.

   ii. Freezeout RAS to trip up to 190 MW of generation in Freezeout area for Aeolus – Freezeout 230 kV line outage depending on pre outage flow conditions.

   There were no additional system improvement requirements identified.

6 Study Conclusions

Technical studies demonstrated that with the addition of the planned D.2 Project facilities to the Wyoming transmission system, system performance will meet all NERC and WECC performance criteria.

Preliminary power flow studies demonstrate that by utilizing existing and planned southeast Wyoming resources[4], the Aeolus West transmission path can transfer up to 1696 MW under simultaneous transfer conditions with the TOT 4B transmission path, effectively[5] increasing the east to west transfer levels across Wyoming by 817.5 MW. Power flow findings also indicated:

- Dynamic voltage control is necessary at the Latham 230 kV substation to mitigate low voltage conditions resulting from loss of Bridger/Anticline – Aeolus transmission facilities.
- Under certain operating conditions, three different Remedial Action Schemes (RAS) will need to be implemented to trip generation following outage of specific transmission facilities.
- The location (and output level) of new and repowered wind resources can influence the transfer capability level across the Aeolus West transmission path.

While a wide range of disturbances were evaluated, dynamic stability studies identified that the slowest post fault voltage recovery will occur for a fault at Anticline or Jim Bridger 345 kV bus followed by loss of the Bridger/Anticline – Aeolus transmission segment and the planned operation of a generation tripping (RAS) scheme. The stability analysis demonstrated that all planned system events met the stability performance criteria.

REDACTED
Rocky Mountain Power
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Direct and Rebuttal Testimony of Rick T. Link

January 2018

Q. Are you the same Rick T. Link who previously provided direct testimony in this case on behalf of Rocky Mountain Power, a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. In my supplemental direct testimony, I summarize the results of the 2017R Request for Proposals ("RFP"). I also provide updates to the economic analysis that demonstrate increasing customer benefits from the new wind resources ("Wind Projects") and construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects").

In my rebuttal testimony, I rebut challenges to the company's economic analysis raised in the direct testimonies of the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni Zenger and Daniel Peaco; Office of Consumer Services ("OCS") witnesses Philip Hayet and Bela Vastag; and the Utah Association of Energy Users and Utah Industrial Energy Consumers ("UAE/UIEC") witness Bradley G. Mullins.

Q. Please summarize your supplemental direct testimony.

A. The 2017R RFP generated robust and competitive responses from market participants. The final shortlist includes four new wind projects located in Wyoming from three different bidders. The total capacity of the four projects is 1,170 MW including three of the benchmark facilities (TB Flats I and II, now combined as a single project, and McFadden Ridge II), and two new facilities (Cedar Springs and Uinta). Uinta is a build-transfer agreement ("BTA") totaling 161 MW, Cedar Springs is one-half BTA and one-half power-purchase agreement ("PPA"), for a total of 400 MW, and TB Flats I and II and McFadden Ridge II are company-built facilities, totaling 500 MW and 109 MW, respectively.

The results of the 2017R RFP and the extensive modeling that supports it confirm that the Combined Projects are the least-cost, least-risk path available to serve the company's customers by meeting both near-term and long-term needs for additional resources. My supplemental direct testimony explains the following:

- The Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $177 million in the medium case through 2050 (as compared to $137 million in the original filing), and range from $311 million to $343 million in the medium case through 2036.
- The analysis reflects changes in federal tax law that were enacted in December 2017, and updated best-and-final pricing from bidders received December 21, 2017, after the federal tax law changes were known.
- The treatment of production tax credits ("PTCs") in the system modeling scenarios extending out through 2036 has been changed to better reflect how the PTCs will flow through to customers, which makes the treatment consistent with the nominal revenue requirement results that extend out through 2050.
- Sensitivity analysis shows substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced when considering the potential procurement of solar PPA bids submitted into the on-going RFP for solar resources, the 2017S RFP.

Q. Please summarize your rebuttal testimony.

A. I address criticisms of the Company's modeling assumptions and methodologies used to develop the economic analysis supporting the Combined Projects. My rebuttal testimony demonstrates that:

- PacifiCorp has near-term and long-term resource needs that will be partially met with the proposed Wind Projects.
- The heavily discounted cost of the Wind Projects is lower cost than all other near-term and long-term resource alternatives.
- Contrary to certain parties' claims, there is nothing novel or unique about the Combined Projects that justifies unprecedented cost-recovery treatment that assigns all risk to the company.
- PacifiCorp's long-standing methodology to develop its official forward price curve ("OFPC") produces the best representation of future market prices and is appropriately used for the central forecast in the company's economic analysis; the alternative price-policy scenarios provide a reasonable foundation for judging risk.
- The company's economic analysis appropriately addresses key project risks that support including the Combined Projects as an important element in PacifiCorp's least-cost, least-risk resource plan.

SUPPLEMENTAL DIRECT TESTIMONY

2017R RFP RESULTS

Q. When did PacifiCorp issue the 2017R RFP?

A. PacifiCorp issued the 2017R RFP on September 27, 2017, after it was approved by the

Public Service Commission of Utah ("Commission") on September 22, 2017, and the Public Utility Commission of Oregon ("Oregon Commission") on September 27, 2017.

Q. Was the scope of the 2017R RFP modified before it was issued to include non-Wyoming wind projects?

A. Yes. The company's original proposal limited the RFP to wind resources capable of interconnecting to or delivering on a firm basis to the company's transmission system in Wyoming. In response to issues raised in the RFP approval process, and consistent with the recommendations of Merrimack Energy Group, Inc., the Utah independent evaluator ("IE"), the company expanded the 2017R RFP to allow bids from non-Wyoming wind projects capable of interconnecting to or delivering on a firm basis to anywhere on the company's transmission system.

Q. In response to the Commission's approval order, did the company decide to issue a solar RFP to run concurrently with the 2017R RFP?

A. Yes. In its order approving the 2017R RFP, the Commission suggested, but did not require, a modification to expand the 2017R RFP to solicit solar resource bids. To maintain the 2017R RFP schedule while addressing the Commission's suggestion, the company issued a separate solicitation process for solar resources, the 2017S RFP, on November 15, 2017. The 2017S RFP sought bids for solar resources up to 300 MW per individual project that can deliver energy and capacity to the company's transmission system.

Similar to the 2017R RFP, the company retained London Economics International, LLC ("Solar RFP IE") as the IE to oversee the solar RFP process. The 2017S RFP schedule allowed the company to: (1) evaluate how solar resource bids might impact the economic analysis of bids selected to the final shortlist in the 2017R RFP without delaying the schedule for the 2017R RFP; and (2) explore whether new solar resource opportunities might provide all-in economic benefits for customers.

Q. When did the company receive initial bids in the 2017R RFP?

A. The company received initial bids for Wyoming wind projects on October 17, 2017, and initial bids for non-Wyoming wind projects on October 24, 2017. The 2017R RFP was well received by the market, as indicated by the fact the company received Wyoming wind proposals from nine bidders offering 49 bid alternatives for 13 wind projects. The company also received non-Wyoming wind proposals from five bidders offering 15 bid alternatives for six wind projects. In aggregate, 5,219 MW of new wind resource capacity was bid into the 2017R RFP (4,624 MW of Wyoming wind and 595 MW of non-Wyoming wind).

Q. When did the company complete its initial shortlist evaluation?

A. The company completed its initial shortlist evaluation and scoring and began a capacity factor evaluation process, performed by Sapere Consulting, on November 12, 2017. The Utah IE and Bates White, LLC, the Oregon IE, completed their review of the initial shortlist on November 17, 2017. Once the IEs completed their review of the initial shortlist, the company notified bidders whether their proposed projects were selected to the initial shortlist and provided an opportunity for bidders selected to the initial shortlist to update pricing. On November 22, 2017, the company received best-and-final pricing for bids selected to the initial shortlist.

Q. Did the company use the best-and-final pricing received on November 22, 2017, to establish the 2017R RFP final shortlist?

A. No. On November 16, 2017, shortly after best-and-final pricing was received, the U.S. House of Representatives passed H.R. 1, which included changes in federal tax law reasonably expected to affect bid pricing. On December 2, 2017, the U.S. Senate passed its own version of a tax-reform bill, setting the stage for a conference committee to reconcile differences between the two bills. On December 7, 2017, the company notified bidders that it would request updated pricing to reflect potential changes in federal tax law once the reconciliation process initiated by Congress was completed. On December 15, 2017, the conference committee approved its report on H.R. 1, and on December 18, 2017, the company notified bidders that updated best-and-final pricing reflecting federal tax provisions outlined in the conference committee's report on H.R. 1 must be submitted by December 21, 2017. The updated best-and-final pricing received on December 21, 2017, was used to establish the 2017R RFP final shortlist.

Q. Were the provisions in the conference committee's report on H.R. 1 ultimately passed by Congress and signed by the President?

A. Yes. Congress passed H.R. 1 on December 20, 2017. The bill became law on December 22, 2017, when it was signed by President Trump.

Q. How did the company select which bids to include in the 2017R RFP final shortlist?

A. Consistent with the bid evaluation and selection process outlined in the Commission-approved RFP, the final shortlist selection process was implemented in two basic phases--the portfolio-development phase and the scenario-risk phase.

Q. Please describe the portfolio-development phase.

A. The portfolio-development phase identifies the least-cost combination of bids using a methodology that is consistent with the approach used to produce resource portfolios in the integrated resource plan ("IRP"). The portfolio-development phase was initiated by processing best-and-final pricing for each bid into the cost-and-performance data required as inputs to the System Optimizer ("SO") model and the Planning and Risk model ("PaR").

The SO model was then used to develop bid portfolios containing the least-cost combination of bids over a twenty-year planning horizon (2017 through 2036). When choosing the least-cost combination of bids, the SO model was configured to select from all of the bids and bid alternatives included in the initial shortlist and all other proxy-resource alternatives used to develop resource portfolios in PacifiCorp's 2017 IRP (*i.e.*, front-office transactions or "FOTs", demand-side management resources, new thermal resources, *etc.*). The company did not force the SO model to select any bid or any combination of bids.

The company developed bid portfolios for nine price-policy scenarios, which, as described in my direct testimony, are developed by pairing three natural-gas price forecasts (low, medium, and high) with three carbon dioxide ("CO_2") price forecasts (zero, medium, and high). I describe updates made to these price-policy scenarios since the company's original filing later in my supplemental direct testimony.

For each price-policy scenario, the company also calculated the present-value revenue-requirement differential ("PVRR(d)") between two system simulations--one that includes 2017R RFP bids and the Transmission Projects and one without. These studies were prepared using the SO model and PaR and are used to quantify the economic impact of top-performing bid portfolios.

The combination of bids selected by the SO model across each of the nine price-policy scenarios and the accompanying PVRR(d) results, calculated using the SO model and PaR, identifies the bid portfolios expected to deliver economic benefits for customers. Specific to the 2017R RFP, this process identified two bid portfolios that were then further evaluated in the scenario-risk analysis phase of the bid-selection process.

Q. When developing bid portfolios, how much new wind capacity could the SO model select in eastern Wyoming?

A. Consistent with the assumptions in my direct testimony, the company assumed that the Aeolus-to-Bridger/Anticline transmission line will enable interconnection of up to 1,270 MW of additional wind resources to PacifiCorp's transmission system in eastern Wyoming. Considering that there is a transmission customer in the interconnection queue with an executed interconnection agreement for a 240-MW qualifying facility ("QF") in the area, the company assumed that sufficient interconnection capacity must be reserved for this transmission customer. Consequently, the company restricted new wind resource bids in eastern Wyoming to 1,030 MW (1,270 MW less 240 MW).

Q. Please describe the scenario-risk-analysis phase of the final shortlist bid-evaluation process.

A. The scenario-risk phase of the bid-evaluation process ensures that the two top-performing bid portfolios identified in the portfolio-development phase of the selection process are analyzed among all nine price-policy scenarios. For instance, one of the bid portfolios identified in the portfolio-development phase includes a consistent set of bids selected by the SO model in five of the nine price-policy scenarios. The second bid portfolio, which includes the same bids that are in the first bid portfolio plus an additional bid, was selected by the SO model in the other four price-policy scenarios. In the scenario-risk phase of the bid-selection process, the first bid portfolio was analyzed in the four price-policy scenarios where it was not selected as the least-cost bid portfolio. Similarly, the second bid portfolio was analyzed in the five price-policy scenarios where it was not selected as the least-cost bid portfolio.

As in the portfolio-development phase, these studies were performed using the SO model and PaR. The outputs from these studies were used to calculate the PVRR(d) between two system simulations--one that includes 2017R RFP bids and the Transmission Projects and one without. The company then used the PVRR(d) results to initially identify the least-cost, least-risk bid portfolio.

Q. Did the company identify any issues in the modeling initially used in the portfolio-development phase and scenario-risk phase of the bid-selection process?

A. Yes. On-going due-diligence review of the least-cost, least-risk bid portfolio allowed the company to identify two issues with specific bids that affected the initial economic analysis. First, the company discovered that capacity factor adjustments applied to two bids were only partially captured in the SO model and PaR simulations. Consistent with recommendations from Sapere Consulting, the net capacity factor for two projects were assessed at 92 percent of the net capacity factor proposed by [redacted]. When applying the net-capacity-factor adjustment in the SO model and PaR, its impact on federal PTC benefits and bid costs were accurately captured.

However, its impact on the expected energy output was not captured. This had the effect of overstating net power cost ("NPC") benefits associated with these bids, one of which was included in the initial least-cost, least-risk bid portfolio.

The second issue was identified when reviewing redline edits made by [redacted] to the 2017R RFP pro-forma BTA. Specifically, the company noticed that [redacted], which submitted several BTA bids, with two of these bids initially included in the least-cost, least-risk bid portfolio, struck language specifying that it would be responsible for applicable sales taxes. [redacted] subsequently confirmed that its price proposals did not include sales tax, and the company confirmed that it did not include sales tax in its evaluation of costs for any of the [redacted] BTA bids.

Q. How did the company evaluate the impact of these two issues in the bid-selection process?

A. The company first corrected the net-capacity-factor inputs for the two projects proposed by [redacted] and included the estimated cost of sales tax on all of the [redacted] BTA bids. Once these corrections were made, the company reran the SO model portfolio-development studies for two price-policy scenarios--one pairing low natural-gas prices with zero CO_2 prices and one pairing medium natural-gas prices with medium CO_2 prices.

Q. Did the correction to the net-capacity-factor inputs for the [redacted] bids cause a change in the bid portfolio in these updated SO model studies?

A. No. The [redacted] bid that was included in the original least-cost, least-risk bid portfolio continued to be selected by the SO model in both price-policy scenarios.

Q. Did the application of sales tax to the [redacted] BTA bids cause a change in the bid portfolio in these updated SO model studies?

A. Yes. When sales tax was added to the cost of the [redacted] BTA bids, one of its two projects that was originally included in the initial least-cost, least-risk bid portfolio was replaced with another bid. Specifically, [redacted] BTA bid for the [redacted] was replaced with [redacted] for the [redacted].

Q. Did the company update its economic analysis to account for this update to the bid portfolio?

A. Yes. The economic analysis among all nine price-policy scenarios was refreshed to reflect this updated bid portfolio, representing the 2017R RFP final shortlist, with corrected cost-and-performance inputs. This analysis was updated using the SO model and PaR. I describe the company's updated economic analysis for the Combined Projects including the 2017R RFP final shortlist later in my supplemental direct testimony.

Q. Did the company inform the Utah and Oregon IEs of changes to the 2017R RFP final shortlist resulting from the corrections applied to the modeling described above?

A. Yes. When issues related to the application of net-capacity factor adjustments and the omission of sales tax in the economic analysis were discovered, the company notified the Utah and Oregon IEs to explain the impact on the 2017R RFP final shortlist and the impact on the economic analysis.

Q. Did the Oregon IE request any additional sensitivity studies during its review of the 2017R RFP final shortlist analysis?

A. Yes. As I will address more fully later in my supplemental direct testimony, the company's bid-selection modeling, performed using the SO model and PaR, reflects nominal federal PTC inputs, to be consistent with how federal PTC benefits will flow into customer rates, where applicable, rather than levelized federal PTC inputs. To understand the impact of this assumption on bid selections, the Oregon IE requested that the company produce an SO model sensitivity, with levelized PTCs, using medium natural-gas price and medium CO_2 price assumptions to understand how treatment of federal PTCs affects bid selection. The Utah IE also expressed interest in seeing this sensitivity.

Q. What were the findings from this IE sensitivity?

A. When federal PTCs applicable to BTA bids and benchmark bids are levelized, the SO model replaces two BTA bids and a benchmark bid with two PPA bids. The PVRR(d) net benefits in the IE sensitivity, calculated from projected system costs through 2036 from the SO model, are lower in the IE sensitivity than they are in the economic analysis using the 2017R RFP final shortlist. In reviewing these results with the IEs, the company also highlighted that the bid portfolio in the IE sensitivity produces higher nominal costs when compared to the economic analysis based on the 2017R RFP final shortlist.

Q. Did the company change its 2017R RFP final shortlist based on the IE sensitivity?

A. No. While the IE sensitivity shows a change in the bid portfolio, this portfolio is selected based on federal PTC inputs that are inconsistent with how PTC benefits will be treated in customer rates. Moreover, the net benefits from the bid portfolio in the IE sensitivity produce lower PVRR(d) benefits and lower near-term nominal net-benefits than the bid portfolio reflected in the 2017R RFP final shortlist.

Q. Please describe the final shortlist of winning bids from the 2017R RFP.

A. The 2017R RFP final shortlist includes four new wind projects located in Wyoming from three different bidders. The total capacity of the four projects is 1,170 MW. The projects included in the final shortlist are summarized in Table 1-SD.

Table 1-SD. 2017R RFP Final Shortlist Projects

Project Name (Bidder)	Location	Capacity (MW)
TB Flats I & II (PacifiCorp)	Carbon & Albany Counties, WY	500
Cedar Springs (NextEra Energy Acquisitions)	Converse County, WY	400
McFadden Ridge II (PacifiCorp)	Carbon & Albany Counties, WY	109
Uinta (Invenergy Wind Development)	Uinta County, WY	161

Q. Are any of the winning bids the company's benchmark resources?

A. Yes. The TB Flats I and II and McFadden Ridge II projects are company-benchmark resources that will be developed under engineer, procure, and construction ("EPC") agreements. The Uinta project is being developed by Invenergy Wind Development under BTAs. The Cedar Springs project is being developed by NextEra Energy Acquisitions as a 50-percent BTA and a 50-percent PPA. In total, the final shortlist includes 361 MW that will be developed under BTAs, 609 MW of benchmark capacity that will be developed under EPC agreements, and 200 MW that will deliver energy and capacity under a PPA.

Q. Please summarize the cost-and-performance attributes of the winning bids.

A. The total in-service capital cost for the winning bids is $1.30 billion, down from the

$1.37 billion assumed in the company's initial filing. Considering that the winning bids represent an increase in total owned-wind capacity (from just over 860 MW in the company's initial filing to approximately 970 MW), the per-unit capital cost for final shortlist bids is down approximately 17 percent from $1,590/kW to $1,320/kW.

In addition to these capital costs, the PPA price that will be paid to NextEra Energy Acquisitions for 50 percent of the output from the Cedar Springs project is expected to add approximately [redacted] to total-system NPC [redacted]. These costs are significantly lower than proxy PPA costs that were based off of certain QF projects that were included in the company's initial filing, which were assumed to add [redacted] to total-system NPC beginning 2022, rising to [redacted] by the end of 2041. This proxy QF project, which requires interconnection facilities beyond the Aeolus-to-Bridger/Anticline transmission line that cannot be built until 2024, is no longer included in the company's economic analysis of the Combined Projects.

In aggregate, the winning bids are expected to operate at a capacity-weighted average annual capacity factor of 40.3 percent.

The in-service cost for network upgrades required to interconnect the final shortlist projects total [redacted], and the cost to build the Aeolus-to-Bridger/Anticline transmission line remains at [redacted]. The expected cost-and-performance attributes for the winning bids and the Transmission Project is summarized in more detail in Confidential Exhibit RMP__(RTL-1SD).

Q. How did the company verify the forecasted capacity factors in its review of bids during the 2017R RFP?

A. The company retained an independent third-party expert, Sapere Consulting, to evaluate the capacity factors proposed for each bid selected to the initial shortlist. Sapere Consulting's report is attached as Confidential Exhibit RMP__(RTL-2SD).

Q. Did the company adjust any of the performance data for bids included in the initial shortlist based on the report prepared by Sapere Consulting?

A. Yes. Consistent with recommendations from Sapere Consulting, the net capacity factor for the [redacted] bids were assessed at 92 percent of the net capacity factor proposed by [redacted]. No adjustments were applied to any of the other bids.

Q. As part of the 2017R RFP process, did the company perform any preliminary viability assessments for the projects included in the final shortlist?

A. Yes. The company reviewed each project's place in the transmission interconnection queue and how each project will qualify for federal PTCs. The company also reviewed bid materials to evaluate site control, progress in collecting avian data, and permitting timelines. All of the projects have either initiated or received system impact studies and are expected to be able to execute interconnection agreements that support the proposed commercial-operation dates. All of the projects will qualify for the full value of PTCs by having secured safe-harbor equipment and by meeting continuity-of-construction requirements, as described in Ms. Nikki L. Kobliha's testimony, by coming online by the end of 2020. All of the final shortlist projects have demonstrated they have site control, have reasonable permitting timelines that will allow the projects to be place in service by the end of 2020, and have initiated collection of avian data.

Q. What is the status of the 2017S RFP?

A. The company received initial bids for new solar resources on December 11, 2017. On January 8, 2018, PacifiCorp established an initial shortlist, considering both price and non-price scoring elements, which was subsequently submitted to the Solar RFP IE for review. As was the case with the 2017R RFP, the market response to the 2017S RFP was robust. The company received solar resource proposals from 31 bidders offering 109 bid alternatives for 46 solar projects. In aggregate, 6,496 MW of new solar resource capacity was bid into the 2017S RFP. After completing its bid-eligibility screening, a process that ensures all bids satisfy minimum-bid requirements that are specified in the 2017S RFP, the company disqualified 32 bid alternatives, which equates to 3,039 MW of new solar resource capacity.

Q. Did the company review those bid alternatives that did not meet minimum-bid requirements with the Solar RFP IE?

A. Yes. The Solar RFP IE reviewed the company's minimum-eligibility criteria and determined that these criteria are consistent with other renewable resource RFPs. The Solar RFP IE also reviewed the specific bid alternatives that were disqualified, and in all instances, found that the disqualified bids clearly did not meet the minimum-eligibility criteria listed in the RFP.

Q. Has the Solar RFP IE commented on any other elements of the on-going RFP process?

A. Yes. On January 10, 2018, the Solar RFP IE submitted its first status report, where it concluded that the 2017S RFP documents are clear and the 2017S RFP has been conducted in a clear and transparent manner.

Q. Please summarize the bids selected to the initial shortlist from the 2017S RFP.

A. The 2017S RFP initial shortlist includes PPAs bids from 10 projects proposed by seven bidders totaling 1,629 MW. The majority of the projects (1,414 MW) are located in Utah, and the remaining initial shortlist bids are located in Oregon (114 MW) and Washington (100 MW). All of the bids on the 2017S RFP initial shortlist have proposed PPAs with commercial-operation dates ranging between November 2020 and January 2021--approximately one year before the initial ramp down in investment-tax credits.

Q. Has the company determined whether it will pursue any bids from the 2017S RFP?

A. No. The company continues to evaluate potential bids in the 2017S RFP and has not yet established a final shortlist. There are several outstanding milestones that have to be met before establishing a final shortlist. Under the 2017S RFP schedule, the Solar RFP IE will complete its review of the initial shortlist no later than January 29, 2018, and then bidders will be asked to submit best-and-final pricing no later than February 5, 2018. Once best-and-final pricing is received, the company plans to identify a final shortlist by mid-March 2018.

Q. Has the company analyzed how the potential selection of bids from the 2017S RFP might affect the economic analysis of the 2017R RFP final shortlist?

A. Yes. Using cost-and-performance data from the bids submitted into the 2017S RFP, the company analyzed how the potential selection of these bids would impact the economic analysis of the winning bids from the 2017R RFP. I describe this sensitivity analysis later in my supplemental direct testimony.

UPDATED ECONOMIC ANALYSIS

Q. What assumptions did the company update before refreshing its economic analysis of the Combined Projects?

A. The models were updated to reflect: (1) cost-and-performance assumptions for the Wind Projects consistent with the winning bids selected to the 2017R RFP final shortlist as summarized earlier in my supplemental direct testimony; (2) current load-forecast projections; (3) current price-policy scenario assumptions; and (4) recent changes in federal tax rate for corporations.

Q. Please describe the updated cost-and-performance estimates for the Wind Projects.

A. The updated economic analysis includes the capital costs associated with the winning bids, the costs associated with the Cedar Springs PPA, and the updated net capacity factors, as described above. The updated economic analysis also captures terminal-value benefits from BTA and EPC-benchmark bids, where the company retains control of the site at the end of the asset life. These benefits were considered in the 2017R RFP bid-selection process, consistent with the bid-evaluation methodology described in the RFP, and therefore, they are applied in the updated economic analysis.

Q. What is captured by the terminal value applied to BTA and EPC-benchmark bids?

A. When a wind asset reaches the end of its life (assumed to be 30 years), equipment associated with the wind asset itself has been fully depreciated. However, transmission assets required to interconnect the wind facility have a longer life (assumed to be 62 years). At the time the wind asset reaches the end of its life, the transmission assets required for interconnection have approximately 32 years of additional life remaining.

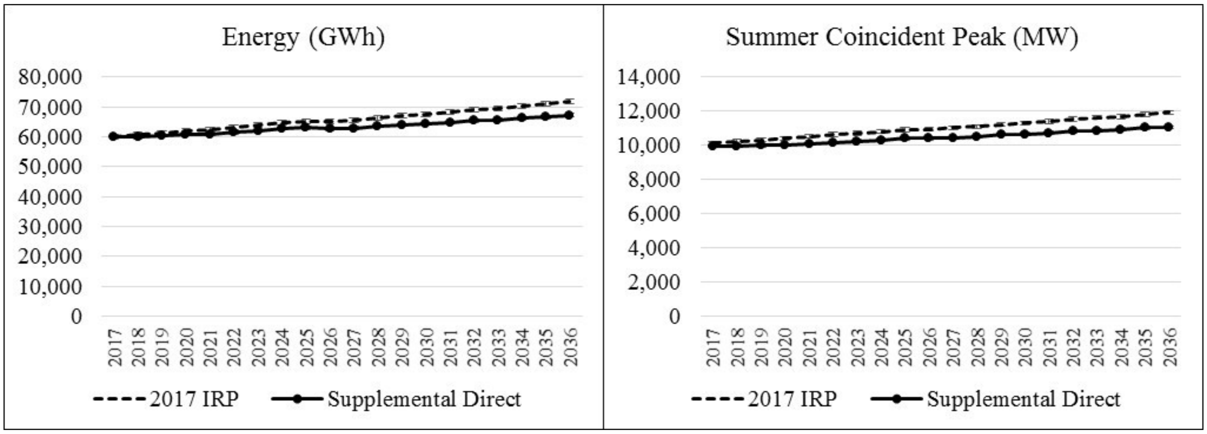
With an owned-wind facility where the company retains control of the site, whether developed as a BTA or an EPC-benchmark, that site can be redeveloped using existing transmission assets that have not been fully depreciated. Consequently, relative to the future development of a new greenfield wind project, the redevelopment of an existing site limits incremental transmission interconnection costs. Similarly, with an owned facility, an existing site can be redeveloped with limited incremental project-development costs, thereby reducing the cost to acquire development rights relative to a new site. These terminal-value benefits are not applicable to a PPA bid, where a third-party retains control of the site.

Q. Please describe the new load forecast assumptions included in the updated economic analysis.

A. The load forecast used in the economic analysis summarized in my direct testimony is the same load forecast used in PacifiCorp's 2017 IRP. This 2017 IRP load forecast was finalized in December 2016. The updated economic analysis uses the company's new load forecast completed in the summer of 2017, after the company made its initial filing.

Figure 1-SD compares the load forecast from the 2017 IRP used in my original economic analysis to the new load forecast. The updated system energy forecast is down by 2.2 percent in 2021 and down by 6.3 percent in 2036 relative to the 2017 IRP forecast. The updated coincident summer peak forecast is down by 4.1 percent in 2021 and down by 7.2 percent in 2036 relative to the 2017 IRP forecast.

Figure 1-SD. Comparison of the 2017 IRP and Updated Load Forecast Assumptions



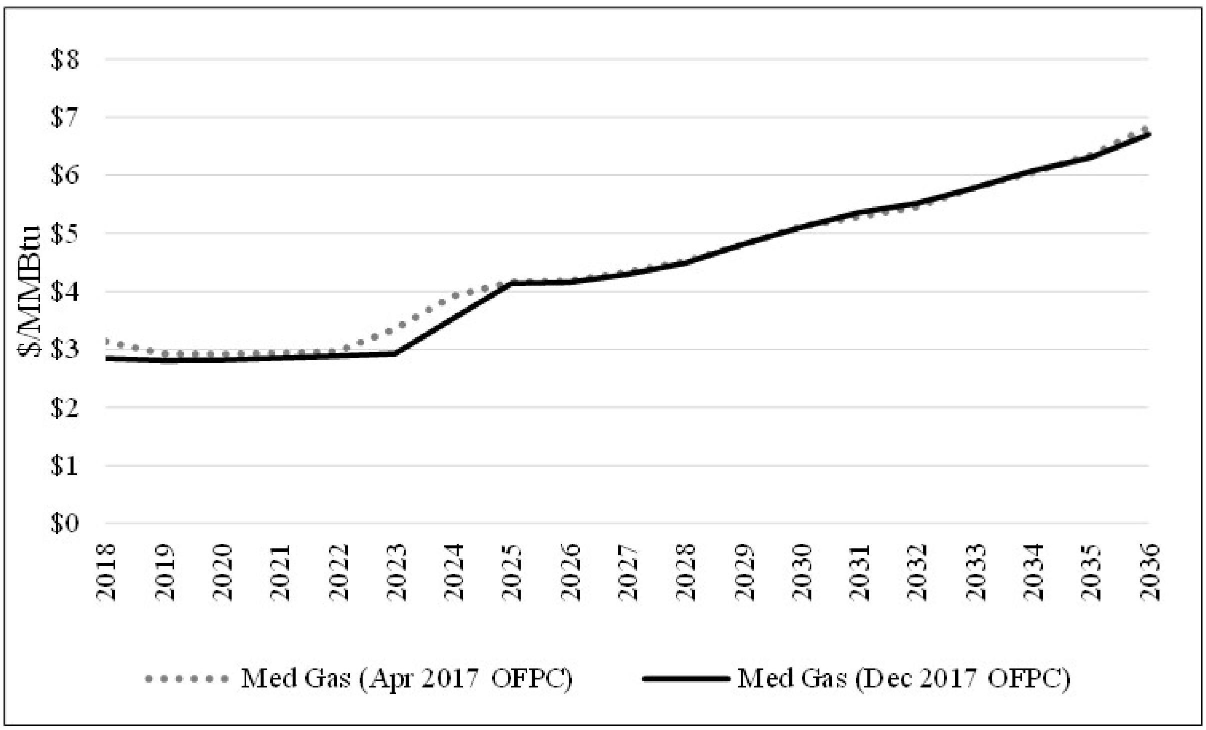
Changes in the load forecast are primarily driven by: (1) a reduction in Utah and Wyoming industrial loads principally due to reduced usage projections for a number of large customers; (2) increases in the growth of customer generation from 2017 to 2018, contributing to reductions in Utah residential customer usage; and (3) updated appliance saturation and efficiency assumptions with refinements to miscellaneous device sales data (*i.e.*, televisions, pool heaters, personal computers, and other plug-in devices), contributing to reductions in Utah residential customer usage.

Q. Please describe the new price-policy assumptions included in the updated economic analysis.

A. In my direct testimony, I described nine price-policy scenarios, developed by pairing three natural-gas price forecasts (low, medium, and high) with three CO_2 price forecasts (zero, medium, and high). The medium natural-gas price assumptions were derived from the company's OFPC. In the economic analysis summarized in my direct testimony, the company used its April 26, 2017 OFPC.

The company's most recent OFPC is dated December 30, 2017, which reflects more current market forwards and an updated forecast from [redacted]. Figure 2-SD compares Henry Hub natural-gas prices from the April 26, 2017 OFPC, as used to support the economic analysis in my direct testimony, with Henry Hub natural-gas prices from the updated December 30, 2017 OFPC. Over the period 2018 through 2036 and using the most current discount rate, the nominal levelized price for Henry Hub natural-gas prices has decreased by approximately three percent from $4.06/MMBtu to $3.94/MMBtu.

Figure 2-SD. Comparison of the April 2017 and December 2017 OFPC Henry Hub Natural Gas Price Forecasts



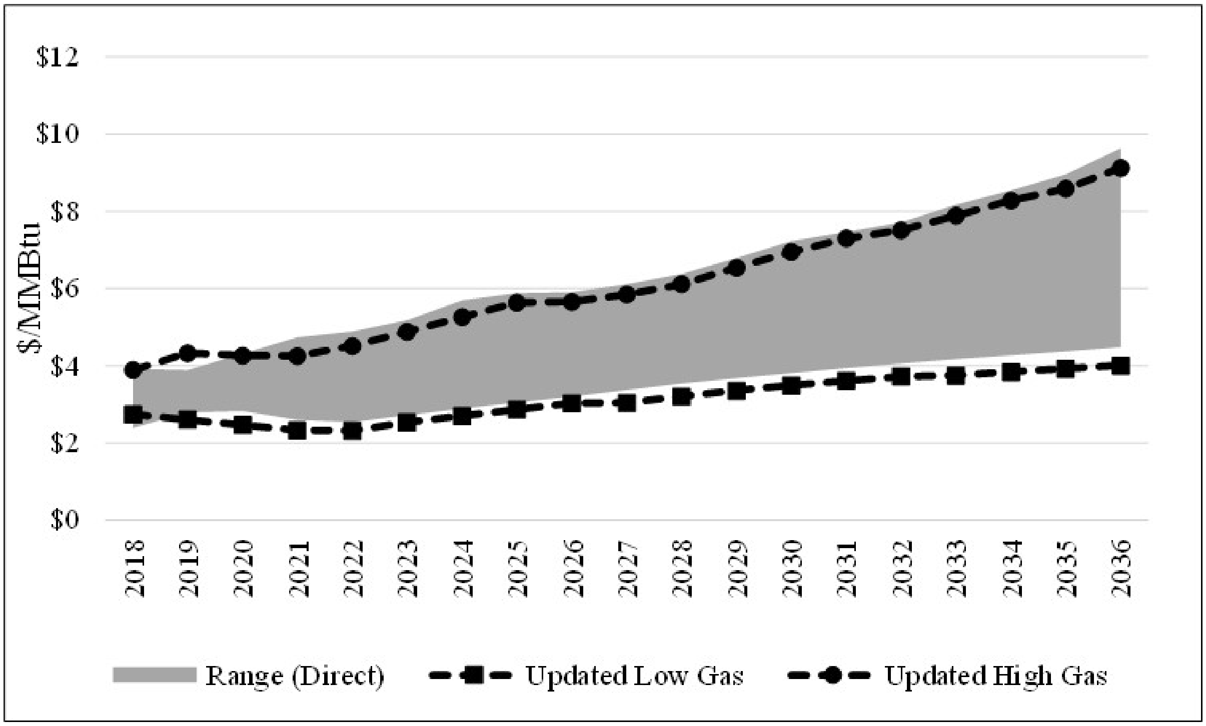
The updated OFPC reflects market forwards as of December 30, 2017 over the period January 2018 through January 2024. The decrease in levelized prices between the updated OFPC and the April OFPC used in the company's original economic analysis is primarily driven by a reduction in market forwards. Prices in the updated market fundamentals forecast from [redacted], which are used exclusively in the OFPC beyond January 2025, track closely with those assumed in the April 2017 OFPC. The company continues to blend market forwards from month 61 (February 2023) through month 72 (January 2024) with the fundamentals-based forecast from month 85 (February 2025) through month 96 (January 2026) to establish prices in month 73 (February 2024) through month 84 (January 2025).

Q. Did the company update the low and high natural-gas price scenarios used in the updated economic analysis?

A. Yes. Consistent with the company's approach to develop low and high natural-gas price scenarios used in the original economic analysis, low and high natural-gas price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted], [redacted], and the U.S. Department of Energy's Energy Information Administration. Exhibit RMP__(RTL-3SD) shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios in the company's updated economic analysis of the Combined Projects.

Figure 3-SD shows the range between the low and high natural-gas price scenarios used in the company's original economic analysis alongside the updated low and high natural-gas price assumptions. Nominal levelized prices in the low and high scenarios are $2.95/MMBtu (down by approximately seven percent) and $5.60/MMBtu (down by approximately four percent), respectively.

Figure 3-SD. Updated Low and High Natural-Gas Price Assumptions



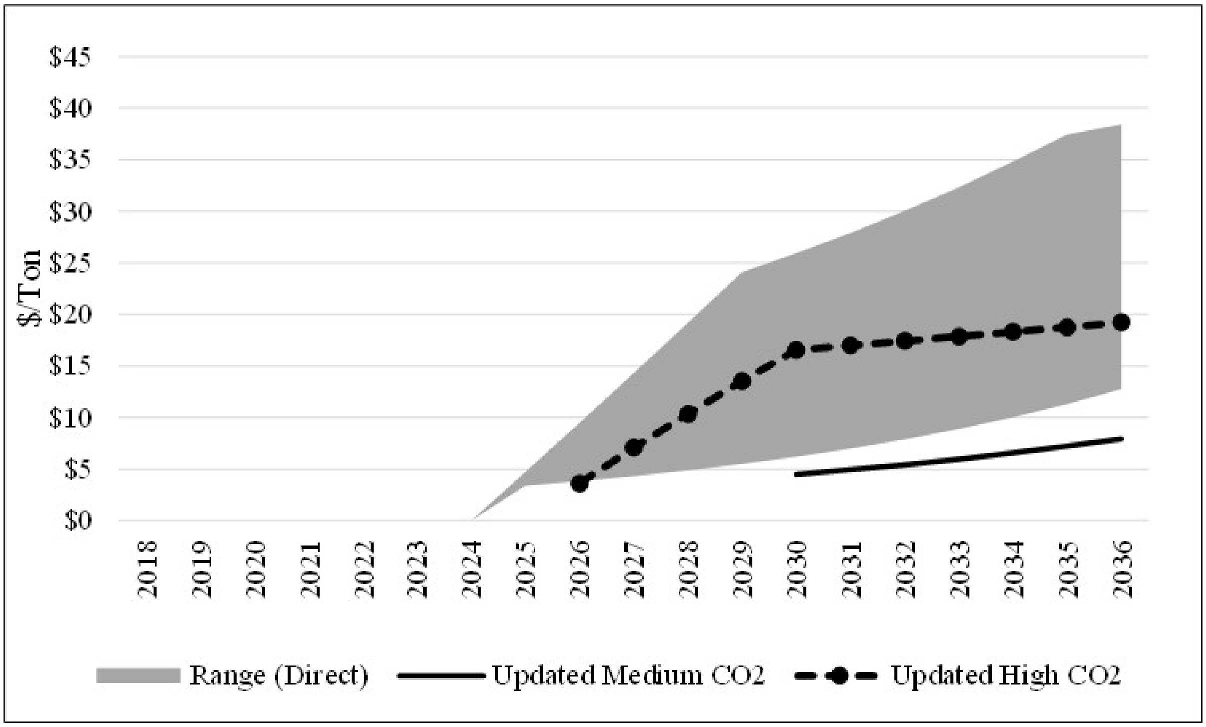
Q. Did the company update its CO_2 price scenarios used in its updated economic analysis?

A. Yes. As with natural-gas price assumptions and consistent with the company's approach to develop low and high CO_2 price scenarios used in the original economic analysis, low and high CO_2 price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted] and [redacted]. To bracket the low end of potential-policy outcomes, the company continues to assume there are no future policies adopted that would require incremental costs to achieve emission reductions in the electric sector. For this scenario, the assumed CO_2 price is zero.

Figure 4-SD shows the range between the medium and high CO_2 price scenarios used in the company's original economic analysis alongside the updated medium and high CO_2 price assumptions. The updated medium and high CO_2 price assumptions are lower and start later relative to the assumptions summarized in my direct testimony.

Updated CO_2 prices in the medium scenario begin in 2030 (five years later) at $4.49/ton and rise to $7.95/ton by 2036. Updated prices in the high scenario begin in 2026 (one year later) at $3.62/ton, rise to $16.55/ton by 2030, and reach $19.23/ton by 2036.

Figure 4-SD. Updated Medium and High CO_2 Price Assumptions



Q. Please describe the updated federal tax rate for corporations that was included in the updated economic analysis of the Combined Projects.

A. The company's updated analysis assumes a 21-percent federal income tax rate. Based on an assumed net state income tax rate of 4.54 percent, the effective combined federal and state income tax rate used in the updated analysis is 24.587 percent.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and PaR in the updated economic analysis.

A. The effective combined federal and state income tax rate affects the company's post-tax weighted-average cost of capital ("post-tax WACC"), which is used as the discount rate in the SO model and PaR. With the changes in tax law, the company's discount rate has been updated from 6.57 percent to 6.91 percent.

The modified income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model, including the selection of bids from the 2017R RFP. As described in my direct testimony, capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital-recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital-recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital-recovery factors applied to new resource costs in the SO model were updated for each simulation of the company's system.

Finally, the updated income tax rate affects the tax gross-up of all PTC-eligible resources. As noted in my direct testimony, the current value of federal PTCs is $24/MWh, which equates to a $38.68/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 37.95 percent. The updated combined federal and state income tax rate reduces the revenue requirement associated with federal PTCs from $38.68/MWh to $31.82/MWh, adjusted for inflation over time. The impact of the updated income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

Q. How were these assumption updates captured in the updated economic analysis of the Combined Projects?

A. The company updated the SO model and PaR to reflect these updated assumptions. As was done in the original analysis summarized in my direct testimony, these models were used to calculate the PVRR(d) between a simulation with and without the Combined Projects after applying the modeling updates. These simulations continue to cover a forecast horizon out through 2036. The company also updated its calculation of the PVRR(d) from the change in nominal revenue requirement due to the Combined Projects through 2050.

Q. In addition to the assumption updates described above, did the company change how it applied federal PTC benefits in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. When establishing the 2017R RFP final shortlist, the company applied PTC benefits for applicable bids (BTAs and benchmark-EPC bids) on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for these bids will flow through to customers and aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050. It also ensures the 2017R RFP bid selections from the SO model more accurately reflect the difference in how BTA and benchmark-EPC bids are expected to impact customer rates.

Q. Did the company continue to apply revenue requirement associated with capital costs on a levelized basis in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. When setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because revenue requirement from capital projects is spread over the life of the asset in rates, these costs continue to be treated as a levelized cost in the SO model and PaR simulations. As was done in the company's original economic analysis to estimate the nominal revenue requirement impacts from the Combined Projects, revenue requirement from capital associated with the Combined Projects is treated as a nominal cost when the results are extrapolated out through 2050.

UPDATED SYSTEM-MODELING PRICE-POLICY RESULTS

Q. Please summarize the updated PVRR(d) results calculated from the SO model and PaR through 2036.

A. Table 2-SD summarizes the updated PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects, reflecting winning bids from the 2017R RFP, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-4SD).

Table 2-SD Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO2	($145)	($104)	($109)
Low Gas, Medium CO2	($186)	($124)	($131)
Low Gas, High CO2	($297)	($258)	($272)
Medium Gas, Zero CO2	($306)	($246)	($258)
Medium Gas, Medium CO2	($343)	($311)	($327)
Medium Gas, High CO2	($430)	($388)	($406)
High Gas, Zero CO2	($619)	($509)	($535)
High Gas, Medium CO2	($636)	($539)	($567)
High Gas, High CO2	($696)	($605)	($636)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $311 million, when derived from PaR stochastic-mean results, and $343 million, when derived from SO model results.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

A. Projected system net benefits increase with higher natural-gas price assumptions, and similarly, increase with higher CO_2 price assumptions. Conversely, system net benefits decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Importantly, both models continue to show that the net benefits from the Combined Projects are robust across a range of price-policy assumptions.

Q. Did you update the potential upside to these PVRR(d) results associated with renewable energy credit ("REC") revenues?

A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 2-SD do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the updated performance estimates discussed above, customer benefits for all price-policy scenarios would improve by approximately $31 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2036 (up from $26 million in my original analysis). Quantifying the potential upside associated with incremental REC revenues is simply intended to communicate that the net benefits from the Combined Projects could improve if the incremental RECs can be monetized in the market.

Q. Is there additional upside to the net benefits shown in Table 2-SD?

A. Yes. Before receiving bids submitted into the 2017R RFP, the company locked down with the IEs default operations and maintenance ("O&M") assumptions that were applied to BTA and benchmark-EPC bids beyond proposed O&M agreement periods. These assumptions were based on the company's experience in operating and maintaining the existing fleet of owned-wind facilities, and were used in the bid-selection process and the economic analysis summarized above.

Since construction of the company's existing fleet of wind facilities, wind technology has evolved and turbine sizes have increased. With the increase in turbine size, O&M costs are expected to be lower than actual experience because there are fewer turbines on a given site. The range in cost savings is expected to vary between 31 to 42 percent of certain O&M cost elements (*i.e.*, materials and O&M contract costs). Two of the winning bids--Invenergy Wind Development's Uinta project and the company's TB Flats I and II project--will use larger-turbine equipment for a portion of the wind turbines on each site. If the O&M cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18-percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $13 million.

UPDATED REVENUE-REQUIREMENT MODELING PRICE-POLICY RESULTS

Q. Did the company update its revenue-requirement modeling among different price-policy scenarios to reflect the modeling updates described above?

A. Yes. Using the same annual revenue-requirement modeling methodology described in my direct testimony, the company updated its forecast of the change in nominal annual revenue requirement due to the Combined Projects, incorporating the modeling updates described earlier my testimony.

Q. Please summarize the updated PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 3-SD summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP__(RTL-5SD).

Table 3-SD. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO2	$169
Low Gas, Medium CO2	$133
Low Gas, High CO2	($105)
Medium Gas, Zero CO2	($60)
Medium Gas, Medium CO2	($177)
Medium Gas, High CO2	($301)
High Gas, Zero CO2	($437)
High Gas, Medium CO2	($479)
High Gas, High CO2	($585)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned wind projects included in the 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer benefits range from $60 million in the medium natural-gas, zero CO_2 scenario, to $585 million in the high natural-gas, high CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the Combined Projects are $177 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results show that upside benefits far outweigh downside risks.

Q. Is there additional potential upside to these PVRR(d) results associated with REC revenues?

A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 3-SD do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the updated performance, customer benefits for all price-policy scenarios would improve by approximately $39 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2050 (up from $34 million in my original analysis).

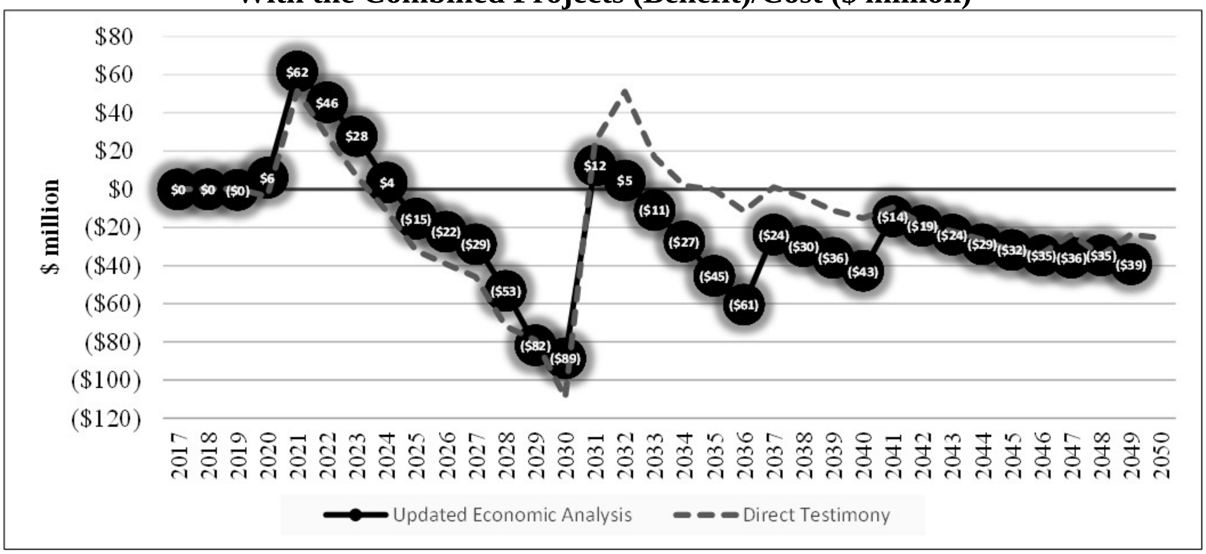
Q. Is there additional potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. As discussed above, the company anticipates O&M costs for those projects that will install larger turbine equipment to be lower than what has been reflected in the updated economic analysis. Accounting for these cost savings, customer benefits for all price-policy scenarios would improve by approximately $22 million when calculated from projected operating costs through 2050.

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

A. Figure 5-SD shows the updated change in nominal revenue requirement due to the Combined Projects for the medium natural-gas, medium CO_2 price-policy scenario on a total-system basis. These results are shown alongside the same results from the original economic analysis summarized in my direct testimony. The change in nominal revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 5-SD Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct testimony. This profile shows that despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits, reduce the magnitude and shorten the duration over which costs increase after federal PTCs for new wind resources expire, and continue to contribute to customer benefits over the long term.

The year-on-year reduction in net benefits from 2036 to 2037 is driven by the company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028-through-2036 time frame. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2033-to-2036 time frame, This extrapolation methodology is conservative because it results in project benefits not matching the levels observed in the model results for 2036 until 2044.

SOLAR SENSITIVITY

Q. Please describe the sensitivity studies that analyzed the impact of the solar bids received in the 2017S RFP on the economics of the Combined Projects.

A. The company's solar sensitivity analysis used the SO model and PaR simulations to determine the PVRR(d) based on two model runs--one with solar PPA bids and the Combined Projects and one with solar PPA bids but without the Combined Projects. In the sensitivity where PPA bids are pursued with the Combined Projects, the SO model continues to choose the winning bids included in the 2017R RFP final shortlist as part of the least-cost bid portfolio. Depending upon the price-policy scenario, between 1,118 MW and 1,315 MW of solar PPA bids, from new projects all located in Utah, are added to the system by the SO model.

Q. What were the results of the solar sensitivity where solar PPA bids are assumed to be pursued in lieu of the Combined Projects?

A. Table 4-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 4-SD Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($334)	($343)	$9
PaR Stochastic Mean	($203)	($311)	$108
PaR Risk Adjusted	($213)	($327)	$114
Low Gas, Zero CO2			
SO Model	($206)	($145)	($61)
PaR Stochastic Mean	($126)	($104)	($22)
PaR Risk Adjusted	($133)	($109)	($24)

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $114 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with solar PPA bids and without the Combined Projects has higher net customer benefits relative to a portfolio containing just the Combined Projects. The increase in net benefits in the solar PPA portfolio is $24 million based on the risk-adjusted PaR results.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SD Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($602)	($343)	($259)
PaR Stochastic Mean	($442)	($311)	($131)
PaR Risk Adjusted	($464)	($327)	($137)
Low Gas, Zero CO2			
SO Model	($286)	($145)	($141)
PaR Stochastic Mean	($185)	($104)	($81)
PaR Risk Adjusted	($195)	($109)	($86)

When the solar PPAs are pursued in addition to the Combined Projects, the total benefits increase, but are diluted (*i.e.*, the aggregate net benefits are less than the sum of the benefits for the cases where Combined Projects or solar PPAs are pursued independently).

Q. What conclusions can you draw from these solar sensitivity analyses?

A. These sensitivities demonstrate that should the company choose to pursue solar bids through the 2017S RFP, the resulting solar PPAs would not displace the Combined Projects as an alternative means to deliver economic savings for customers.

While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces a PVRR(d) with net benefits that are slightly higher than a portfolio without the solar PPAs in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. This sensitivity does not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table. Importantly, the sensitivity that evaluates the Combined Projects with the solar PPAs produces net benefits that are greater than the net benefits from the Combined Projects without the solar PPAs. This confirms that near-term renewable procurement is not a matter of whether the company should pursue the Combined Projects *or* the solar PPAs, but whether the company should consider both opportunities. At this time, it is clear that the Combined Projects provide significant net benefits, and that these benefits are not eliminated if the company were to also pursue solar PPA bids through the 2017S RFP.

WIND-REPOWERING SENSITIVITY

Q. Has the company updated its sensitivity analysis related to the wind repowering project?

A. Yes. Based on the updates discussed above, coupled with the updated cost-and performance estimates for the wind repowering project (described in Docket No. 17-035-39), the company performed a sensitivity that includes the repowered wind facilities assuming they continue to operate within the limits of their large generator interconnection agreements ("LGIAs").

Q. What were the results of the wind-repowering sensitivity?

A. Table 6-SD summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 6-SD Wind-Repowering Sensitivity (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($541)	($343)	($198)
PaR Stochastic Mean	($475)	($311)	($164)
PaR Risk Adjusted	($498)	($327)	($171)
Low Gas, Zero CO2			
SO Model	($313)	($145)	($169)
PaR Stochastic Mean	($255)	($104)	($152)
PaR Risk Adjusted	($268)	($109)	($159)

In the wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural-gas, medium CO_2, and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but also increase, if both the wind-repowering project and the Combined Projects are completed.

REBUTTAL TESTIMONYRESOURCE NEED

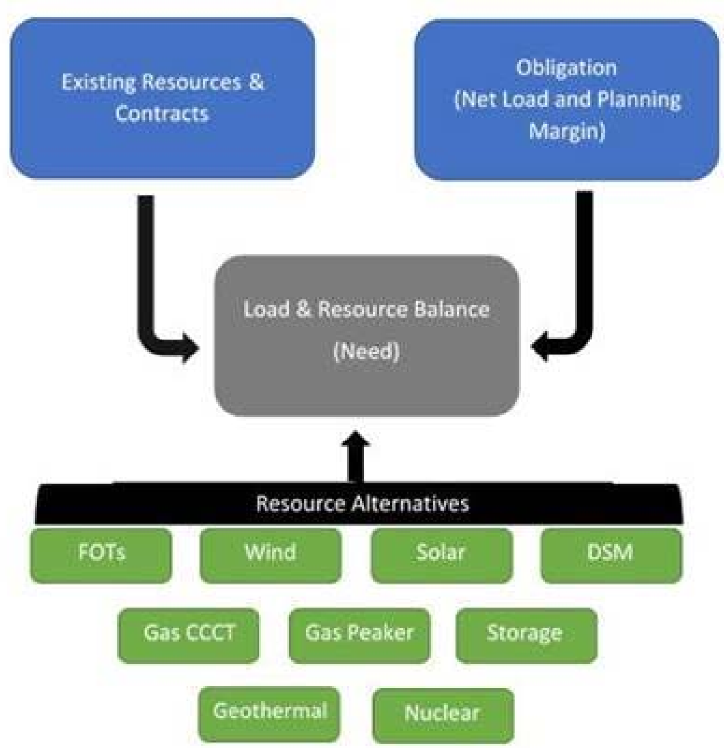
Q. Dr. Zenger, Mr. Vastag, and Mr. Mullins argue that the Combined Projects are not tied to a specific resource need. (Zenger Direct, pages 9-11; Vastag Direct lines 53-64; Mullins Direct, page 10, lines 17-20.) Do you agree?

A. No. The Combined Projects meet both near-term and long-term resource needs identified in the company's 2017 IRP. The Combined Projects leverage federal PTCs to provide least-cost resources that meet these needs, and do so with substantial savings to customers.

Q. How does the company develop its forecast of resource need?

A. Resource need is the product of a load-and-resource balance, which is reported in the IRP. Figure 1-R summarizes the elements of the load-and-resource balance that are used to establish resource need, and once identified, how that need can be met.

Figure 1-R. Elements of the Load-and-Resource Balance



There are two basic elements to the load-and-resource balance: (1) existing resources and committed contracts; and (2) obligations. Existing resources and committed contracts account for any planned or assumed resource retirements and contract terminations over time. Obligations include load, net of customer-sited generation and interruptible contracts, over time. Obligations also include a planning margin, which represents an incremental planning requirement, applied as an increase to the projected obligation, to ensure sufficient capacity on the system to manage uncertain events (*i.e.*, weather and outages) and known requirements (*i.e.*, operating reserves). In recent IRPs, including the 2017 IRP, the company assumes a 13-percent planning margin.

The load-and-resource balance reflects the difference between these two basic elements. When existing resources and contracts exceed obligations, the company has sufficient resources to reliably meet customer needs. When existing resources and contracts are less than its obligations, the company has a resource need. This balance between existing resources, including committed contracts, and obligations can change over time. When the company faces a resource need, the IRP is used to evaluate a wide range of supply-side resources (*i.e.*, renewable resources, gas-fired resources, uncommitted front-office transactions or “FOTs”, *etc*.) and demand-side resources (*i.e.*, demand-side management resources or “DSM”) that can be used to meet that need over time. Different types of resource portfolios that can be used to meet a resource need are evaluated in the IRP to determine which portfolio is least cost, accounting for risk.

Q. Does the load-and-resource balance presented in the 2017 IRP show a near-term resource need?

A. Yes. Accounting for assumed resource retirements, contract terminations, and incremental DSM savings from the preferred portfolio, the 2017 IRP shows a near-term resource need of 527 MW in 2017 rising to 1,023 MW in 2021, the first full year the Combined Projects will be placed in service.[1] The resource need grows over time with load growth, existing resource retirements, and committed contracts terminations.

Q. Do the Combined Projects fully satisfy the near-term resource need identified in the 2017 IRP load-and-resource balance?

A. No. In the 2017 IRP, the company updated its capacity contribution values for wind and solar resources. Based on these values, 15.8 percent of Wyoming wind resource capacity can be relied upon at times when the system is most likely to experience conditions where load exceeds available resources. Consequently, the 1,100 MW of new Wyoming wind in the 2017 IRP preferred portfolio meets approximately 174 MW (17 percent) of the 1,023 MW resource need in 2021. The remaining resource need in 2021 (83 percent) is met with uncommitted FOTs.

Q. If the Combined Projects were not included in the resource portfolio, how would the 2021 resource need be met?

A. Resource portfolios that do not include the Combined Projects include more uncommitted FOTs. The resource portfolios with more uncommitted FOTs are higher cost than resource portfolios that include the Combined Projects under a wide range of price-policy scenarios. Simply stated, resource portfolios with the Combined Projects

[1] Table 5.15, PacifiCorp's 2017 IRP, Volume I.

displace FOTs in the near-term because the Combined Projects, accounting for PTC savings, are lower cost and lower risk than FOT resource alternatives.

Q. Has the company previously acquired renewable resources that displace FOTs?

A. Yes. This is not the first time the company has implemented a least-cost, least-risk plan to procure renewable resources that displace uncommitted FOTs. In fact, all 1,698 MW of PacifiCorp's existing contracted and owned renewable resources included in rates today, not including QFs, were acquired and approved by the Commission because they were the least-cost, least-risk resources, displaced FOTs, and were acquired well before any thermal capacity or state renewable portfolio standard need.

Q. Mr. Mullins claims that FOTs do not represent fulfillment of a resource need. (Mullins Direct, page 15, lines 1-4.) Is this true?

A. No. Mr. Mullins claims that the 2017 IRP shows currently available resources and FOTs will meet the company's resource needs through 2026 and therefore the Combined Projects "cannot be reasonably characterized as addressing a resource need." (Mullins Direct, page 12, lines 10-11.) This claim improperly assumes that the maximum level of FOTs assumed in the IRP are committed resources and that other resource alternatives, such as the Combined Projects, cannot be used to meet the projected resource need at a lower cost. As noted above, in the IRP, FOTs represent *uncommitted* resources, meaning they can be displaced if lower-cost alternatives are available. As the 2017 IRP shows, the energy and capacity provided by the Wind Projects are lower cost than other resource alternatives, including FOTs.

Q. Is Mr. Mullins' testimony here inconsistent with prior positions taken by UAE?

A. Yes. I understand that in Docket No. 15-035-53, UAE (as part of the Rocky Mountain

Coalition for Renewable Energy ("Coalition")), argued that it was "incorrect . . . that the [company's 2015] IRP shows no need for additional resources for over a decade, and that QF PPAs thus represent unneeded resources." *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Docket No. 15-035-53, Post Hearing Brief of the Rocky Mountain Coalition for Renewable Energy at 9-10 (Dec. 9, 2015). UAE argued: "To the contrary, the IRP demonstrates a need for significant new resources, which PacifiCorp primarily proposes to secure through short-term FOTs." *Id. See also In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Docket No. 15-035-53, Tr. pg. 234, lines 11-20 (Nov. 12, 2015) (Coalition witness Kevin C. Higgins testified that the "IRP calls for the purchase of around one million megawatt hours per year in front-office transactions from 2016 to 2024" and that these transactions could be displaced by lower cost alternatives). Mr. Mullins' position here, on behalf of UAE, is contradicted by UAE's prior advocacy.

Q. Has any other party recognized that FOTs are used to meet near-term resource needs?

A. Yes. I understand that in the company's 2015 IRP docket, DPU noted: "Near-term resource needs continue to be met with DSM and FOTs." *PacifiCorp's 2015 Integrated Resource Plan*, Docket No. 15-035-04, Division Comments on PacifiCorp's 2015 IRP at 24 (Aug. 25, 2015). Thus, DPU's position in this case is also contradicted by its prior comments.

Q. What factors influence the type of resources used to meet the company's resource need over the long term?

A. Uncommitted FOTs are traditionally one of the lowest-cost resources that can be used to meet a resource need. This is because the cost of these FOT resources reflect only the marginal, variable operating cost of existing resources selling excess firm energy to market participants on a forward basis. While the availability of PTCs changes this dynamic for the Combined Projects, supporting their inclusion in the company's resource portfolio by the end of 2020, uncommitted FOTs are still generally lower cost than *other* resource alternatives. Consequently, as the resource need grows over time, the level of uncommitted FOTs in the preferred portfolio generally grows, approaching maximum limits.[2] The timing in which the resource need exceeds maximum uncommitted FOT limits, after accounting for other lower-cost alternatives such as the Combined Projects, is a strong indicator of when the company will require incremental generating resources to meet its long-term resource need.

Q. How do the new wind resources included in the company's 2017 IRP preferred portfolio meet a long-term resource need?

A. The company's 2017 IRP forecasts that maximum levels of uncommitted FOTs begin to exceed resource needs by just under 400 MW beginning in 2028. The 1,100 MW of Wyoming wind resources included in the 2017 IRP preferred portfolio in 2021 contributes 174 MW of system capacity. Consequently, the 2017 IRP analysis shows that these new wind projects will meet approximately 44 percent of the resource need

[2] These maximum limits are based on the company's active participation in the wholesale power markets, physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply.

incremental to the resource need that can be met with FOTs. Therefore, beginning in 2028, the new wind resources included in the 2017 IRP preferred portfolio in 2021 begin deferring the need for other, high-cost resource alternatives. In this sense, these new wind resources can be viewed as displacing higher-cost uncommitted FOT resources in the near-term and deferring other higher-cost resource alternatives over the long-term.

Q. While these new wind resources will be used to meet both near-term and long-term resource needs, are you aware of examples where the Commission deemed early acquisition prudent?

A. Yes. I understand that in 1974, the Commission found that the company's decision to overbuild capacity at its Huntington plan was prudent because "substantial long-range benefits will accrue to the Utah ratepayers by having the additional facilities at the lower cost . . . and that Utah Power made a wise decision in constructing the larger generation unit when it had the opportunity to do so." *Re Utah Power & Light Co.*, 6 P.U.R.4th 263 (1974) (finding it prudent to increase capacity from 300 MW to 400 MW and sell near-term excess capacity until needed to serve customers).

Q. Dr. Zenger, Mr. Vastag, and Mr. Hayet claim that the Combined Projects are an economic opportunity to capture PTCs and not tied to resource need. (Zenger Direct, lines 236-239; Vastag Direct, lines 1-2, 55-64; Hayet Direct, lines 148-149.) Is this a fair characterization of the Combined Projects?

A. No. The company's analysis shows that acquiring the new wind resources now, when they are PTC-eligible, will displace higher-cost resources in both the near and long terms. The PTCs affect the timing and economics of the new resource, not the need for the resource. The fact that the Combined Projects are a time-limited opportunity based on PTCs does not inherently indicate that they are disconnected from a resource need.

Q. Mr. Mullins claims that the Combined Projects could be viewed as a hedge against market prices, but that this benefit should be ignored. (Mullins Direct, page 16, lines 11-20.) How do you respond?

A. First, the company agrees that wind resources provide a valuable hedge against future price volatility and the risk of future carbon regulation because wind resources have no fuel costs or carbon emissions, facts I understand that the Commission has previously recognized. *See In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts*, Docket No. 12-035-100, Order on Motion to Stay Agency Action at 17 (Dec. 20, 2012) ("wind resources provide ratepayers a hedge against fuel price and environmental risks"). The company's assessment of the Combined Projects appropriately accounted for the valuable risk mitigation provided by wind resources.

Second, contrary to Mr. Mullins' characterization, the Combined Projects are not being acquired "solely for hedging value." (Mullins Direct, page 16, lines 19-20.) As discussed above, the Combined Projects meet an identified resource need and are lower cost and lower risk than other resource alternatives, including FOTs. The fact the Combined Projects provide hedging value and further reduce the company's generation portfolio risk is an attribute of the projects, not a fault.

Q. Mr. Mullins indicates that he was surprised when the company announced as part of its 2017 IRP process that its preferred portfolio included the Combined Projects. (Mullins Direct, page 6, lines 14-19.) Dr. Zenger claims that the Commission should be skeptical of the Combined Projects because they were introduced late in the planning process. (Zenger Direct, lines 247-255.) How do you respond?

A. The Combined Projects were a logical development as the 2017 IRP analysis evolved. In late 2016 and early 2017, the company continued to study and refine its resource portfolios, all of which contained new Wyoming wind resources. In reviewing these resource portfolios, it became clear that the amount of Wyoming wind included in these resource portfolios was limited by transmission constraints. The presence of the Wyoming wind resources in these initial portfolios led the company to assess whether additional wind resources enabled by advancing sub-segments of Energy Gateway West would further lower system costs. Consequently, after the January 2017 public input meeting, the company incorporated the Aeolus-to-Bridger/Anticline line as a specific sensitivity case in its broader Energy Gateway sensitivity analysis. In late February, the company's modeling of four Energy Gateway transmission sensitivities indicated there were potential benefits to including the Aeolus-to-Bridger/Anticline line in the portfolio. At the March 2017 public input meeting, the company presented this preliminary analysis to stakeholders, along with next steps that communicated the company's intention to further refine key assumptions for this sensitivity case.

While the pre-filing stakeholder review process of the Combined Projects was necessarily limited by the timing of the company's analysis and 2017 IRP filing deadlines, it was in customers' interest to consider these resources and ultimately include them in the 2017 IRP preferred portfolio. The company explicitly chose to share the results of its analysis with stakeholders as it was being produced. Given the time-sensitive nature of these resource opportunities, delaying the IRP to allow additional pre-filing review was not a viable option. Instead, the company expeditiously completed the necessary analysis and shared it with IRP stakeholders in real time.

Q. Were there wind resources in other scenarios?

A. Yes. The 2017 IRP analyzed all alternatives when identifying ways to meet customers' near-term and long-term resource needs, including incremental DSM savings, procurement of uncommitted FOTs, new supply-side resources, including new renewable resources, and changes in use of or upgrades to existing resources to develop the preferred least-cost, least-risk portfolio of resources. The company's 2017 IRP shows a need for new resources that can be partially met with new wind generation by the end of 2020 across almost all modeled portfolios. The company examined alternatives for meeting this near-term need, but transmission constraints limited wind resource options.

Q. Mr. Hayet argues that the preferred portfolio that included the Combined Projects was not "significantly better" than other modeled portfolios. (Hayet Direct, lines 138-40.) How do you respond?

A. It is not clear which of the many portfolios that the company developed and analyzed in the 2017 IRP that Mr. Hayet believes might be lower cost and lower risk than the preferred portfolio. Similarly, Mr. Hayet does not identify what criteria he is using to determine why some other resource portfolio should have been selected as the preferred portfolio. The company's selection of the preferred portfolio is supported by robust analysis and a thorough screening process that considers expected costs, risk, reliability, emissions, fuel diversity, and customer rate impacts. Throughout the portfolio-development-and-screening process, top-performing resource portfolios consistently included new PTC-eligible wind facilities. Resource portfolios that included the Aeolus-to-Bridger transmission line, which enables additional PTC-eligible wind resources, produced a risk-adjusted PVRR that was notably lower than portfolios that excluded these investments.

Q. Mr. Peaco claims that "the only alternative to the Combined Projects is not to pursue them" because there is no need for additional resources. (Peaco Direct, lines 293-297.) Are there risks associated with not pursuing the Combined Projects?

A. Yes. If the company does not pursue the Combined Projects, it will be forgoing the opportunity for customers to acquire heavily-discounted resources in the near term, in exchange for greater reliance on near-term market transactions and waiting until after the expiration of PTCs to acquire zero-fuel-cost resources to meet growing energy and capacity needs. Contrary to parties' implication that there are no customer risks associated with forgoing the opportunity to procure PTC-eligible resources, there are risks associated with greater reliance on higher-cost FOT resources over the near term and greater reliance on other higher-cost resources over the long term—and those risks will be borne by customers.

Although parties point out the risks of the Combined Projects, they do not demonstrate that they are higher risk than the next best alternative. In contrast, the 2017

IRP and the economic analysis summarized in this testimony clearly demonstrates that the Combined Projects are least-cost, least-risk compared to all other alternatives, including the status quo alternative, which will result in increased reliance on higher-cost FOTs. Indeed, greater reliance on FOTs, in lieu of the Combined Projects, is expected to cost more under every combination of natural gas and CO_2 price scenario studied using the SO model and PaR with a forecast horizon extending through 2036.

Q. Have any parties to this case previously expressed concern over the risks associated with the continued reliance on market transactions?

A. Yes. When the company requested authority to terminate its RFP for 2016 resources, I understand that DPU noted that it "and others have for several years questioned the company's continued reliance on front office transaction (FOTs) (*i.e.*, short-term wholesale power purchases) in the company's bi-annual integrated resource planning process." *PacifiCorp's All Source Request for Proposals for a 2016 Resource*, Docket No. 11-035-73, Memorandum of the Division of Public Utilities at 4 (Jan. 14, 2013). DPU continued: "The termination of this RFP continues the company's reliance on FOTs and in the near- to intermediate-term may increase its reliance on these wholesale purchases together with the continued risks the Division associates with such reliance." *Id.* Similarly, OCS reiterated its concern "with the company's reliance on front office transactions in the long term." *PacifiCorp's All Source Request for Proposals for a 2016 Resource*, Docket No. 11-035-73, Memorandum of the Office of Consumer Services at 2 (Jan. 14, 2013).

I understand that DPU reiterated its concerns in the 2015 IRP docket. First, DPU noted: "For all of the years under review, the obligation or system requirement is greater than the available resources." *PacifiCorp's 2015 Integrated Resource Plan*, Docket No. 15-035-04, Division Comments on PacifiCorp's 2015 IRP at 16 (Aug. 25, 2015). DPU then observed that the company closes this resource deficit by relying "more heavily on FOTs to satisfy the difference" and that the "reliance on FOT transactions continues to be a concern to the Division and to other Utah parties." *Id.* According to DPU, the "reliance on the wholesale electric market could result in ratepayers facing greater price volatility and potentially loss of power except at very high prices in the event that the wholesale markets dry up due to environmental concerns and the possible closure of existing coal fired generation facilities, among other reasons." *Id.*

Q. Has any party provided meaningful analysis demonstrating that the status quo is less risky than pursuing the Combined Projects?

A. No. In asserting, without analysis, that the status quo yields superior outcomes, the parties discount the availability of a lower-cost, lower-risk alternative. To the extent they assume inaction is less risky than action, this assumption lacks either logical or factual support. There is nothing about inaction that makes it preferable to action when objectively considering relative risk. For the Combined Projects, nearly every modeling scenario results in customer benefits. Declining to pursue the Combined Projects results in a likely opportunity cost—that is, a likely customer loss.

The parties' recommendation against the Combined Projects is substantially more likely to achieve a less favorable outcome for customers in the form of increased costs and increased risk—a result inadequately justified by the preference for inaction over action. The company seeks to develop the Combined Projects now because the PTCs make this the least-cost, least-risk option to serve current capacity and energy needs. Inaction will forgo a valuable opportunity, and delaying the acquisition of least-cost resources in favor of higher-cost alternatives is not in the best interest of customers.

Q. Both Dr. Zenger and Mr. Mullins also argue that the company has an incentive to invest in the Combined Projects and suggest that this incentive is improperly driving the investment decision. (Mullins Direct, page 9, line 1-2; Zenger Direct, lines 117-119.) How do you respond?

A. These claims ignore the resource need discussed above. Mr. Mullins further supports this conclusion by citing the Averch-Johnson thesis, which theorizes that traditional rate-base and rate-of-return regulation biases a regulated firm, as compared to an unregulated one, toward more capital-intensive modes of production. Mr. Mullins' reliance on the Averch-Johnson thesis is misplaced, however, because there is considerable debate about whether the Averch-Johnson effect is real and, even if it is real, whether such an effect would be undesirable.[3]

This argument also ignores that the Combined Projects are more cost-effective than FOTs, even when including capital and run-rate operating costs. A higher-cost resource should not be selected merely to prevent an opportunity for shareholders to earn a rate of return.

[3] Charles F. Phillips, Jr., The Regulation of Public Utilities 892-93 (1993); see also James C. Bonbright et al., Principles of Public Utility Rates 362 (2d ed. 1988) ("[T]o the extent [the Averch-Johnson effect] exists, it could well be a more important influence for good than for poor performance[.]") (quoting Alfred E. Kahn, Applications of Economics to Utility Rate Structures, 101 Public Utilities Fortnightly 59 (Jan. 19, 1978)); id. ("To repeat: we find a paucity of data documenting the Averch-Johnson effects and instead find largely educated speculation."). A recent meta-analysis of scholarship concerning the Averch-Johnson effect concluded that it amounts to "an intellectual curiosity," and suggested that further efforts to discern an Averch-Johnson effect on regulated utilities be "abandoned in favour of more productive enterprises." Stephen M. Law, Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities, 6 INT'L J. OF ECON. & FIN. 41, 42, 52 (2014).

Q. Dr. Zenger also argues that if the Commission approves the Combined Projects here it will "likely lead to unwanted future utility actions." (Zenger Direct, lines 257-261.) Is this a valid concern?

A. No. Dr. Zenger's concern is about unwarranted resource development, and it is not clear how that could occur given the Commission's standard for reviewing the prudence of new resource acquisitions. The only scenario in which Dr. Zenger's fears could materialize—excessive capital investment at excessive ratepayer risk—requires the Commission to change its prudence review standard to ignore the reasonableness of the utility decision-making based on what the utility knew or should have known at the time of the acquisition decision.

Q. Dr. Zenger argues that the Combined Projects do not represent an "ordinary" resource acquisition. (Zenger Direct, lines 228-231.) Do you agree?

A. No. There is nothing novel or unique about the Combined Projects that require heightened review or a different standard for approval. Dr. Zenger does not challenge the fact that the company has an energy and capacity need in 2028. At the very least, the Combined Projects are an early acquisition. Dr. Zenger provides no support for the position that shareholders should bear greater risk when a utility prudently acquires a resource ahead of need. The Combined Projects do not present risks different than typical utility investments. The company's analysis shows that benefits from the Combined Projects accrue to customers in the near-term, well before the alleged 2028 capacity deficiency.

ECONOMIC ANALYSIS

Q. Mr. Mullins, Mr. Hayet, and Mr. Peaco argue that the company has overstated the economic benefits of the Combined Projects because natural gas prices in the base case scenario are too high. (Mullins Direct, page 23, lines 9-15; Hayet Direct, lines 271-297; Peaco Direct, lines 734-735) How does the company determine the forecasted natural-gas prices used for the economic analysis?

A. The medium (or base case) forecast is the company's OFPC, which uses observed forward market prices for the first 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by a reputable third-party expert. The low and high natural-gas price assumptions were also based on recent forecasts developed by reputable third-party experts. The company verified the reasonableness of the third-party forecasts by comparison to forecasts prepared by others, including the U.S. Department of Energy's Energy Information Administration.

Q. Is the OFPC used in the company's economic analysis the same forecast the Commission has used for ratemaking, setting avoided costs rates, and evaluating both demand- and supply-side resources?

A. Yes. The OFPC, which represents the medium-natural-gas-price case is the same forecast used for setting net power costs in the company's Utah rates. It is also used when the company calculates avoided cost prices paid to QFs, and evaluates the cost-effectiveness of demand-side and supply-side resources.

Q. Has the DPU previously testified regarding the reliance on the forward price curve when making resource decisions?

A. Yes. I understand that in Docket No. 12-035-102, the DPU testified that "future prices will likely be different from the forward price curve, but if the forecast is unbiased, *i.e.*, that it is equally likely that the actual future prices are higher or lower than the forecasted prices, [] the best approach is to simply act today on its forecast as the best indicator of future outcomes." *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources*, Docket No. 12-035-102, Pre-Filed Direct Testimony of Douglas D. Wheelwright on Behalf of Utah Division of Public Utilities at lines 326-330 (Mar. 5, 2013). DPU noted that if "one had information today that the longer-term future was likely to be different from the above forecast, then the above analysis could be invalidated by the additional information." *Id.* at 330-332. In this case, however, there is no additional information indicating that the longer-term future is likely to be different from the OFPC and therefore, according to the DPU's prior analysis, the "best approach" is to act today based on the OFPC.

Q. How does the company use each of the price-policy scenarios in its analysis?

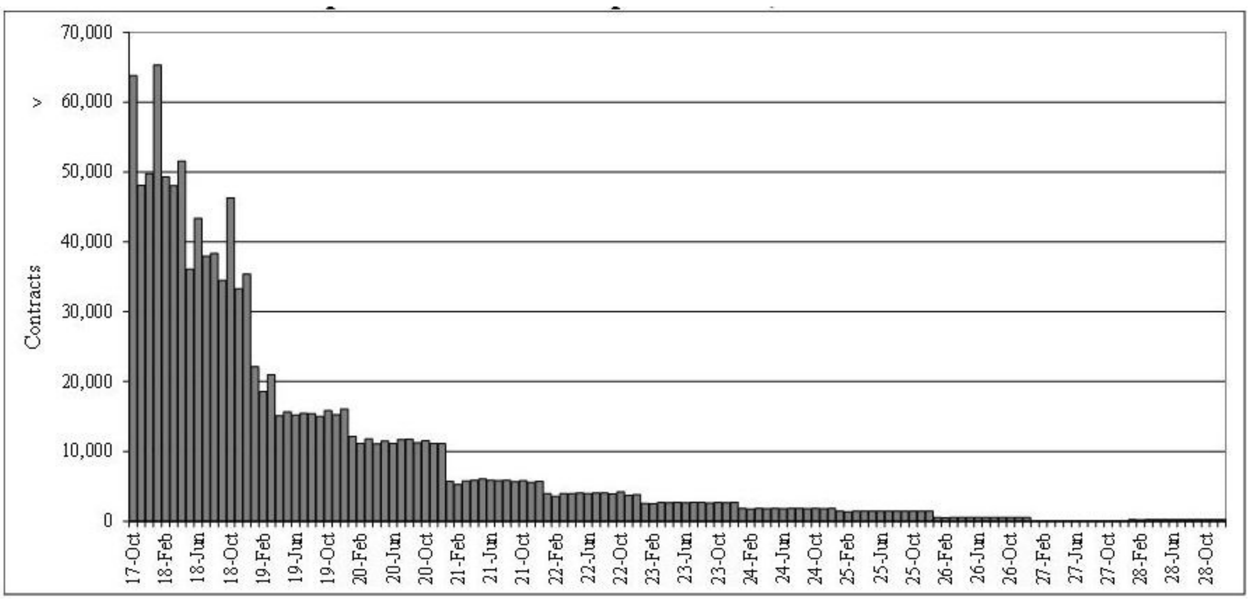
A. The price-policy scenario assuming medium natural-gas prices and medium CO_2 prices represents the central forecast, around which the impact of lower or higher price assumptions can be evaluated. In the company's updated economic analysis, the PVRR(d) net benefit of the Combined Projects derived from the central price-policy scenario is $177 million when calculated from projected nominal system costs through 2050. This outcome indicates that, when central price-policy assumptions are used, there is a reasonably sized cushion in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices and CO_2 prices end up lower than what is assumed in this scenario. The other price-policy scenarios are useful in quantifying how sensitive the PVRR(d) results are to these key assumptions and provide a foundation for judging risk. Importantly, however, the company's updated analysis now shows robust customer benefits in nearly all price-policy scenarios without even accounting for potential upside benefits not reflected in the economic analysis.

Q. Mr. Peaco compares the company's natural-gas price forecasts with NYMEX Henry Hub natural-gas futures through 2029 as of November 28, 2017, and concludes that the NYMEX forecast is "at least as important to consider" as the company's OFPC. (Peaco Direct, lines 722-723.) How do you respond?

A. Mr. Peaco's reliance on NYMEX futures is misguided because it relies solely on NYMEX Henry Hub natural-gas futures after 2022, which do not accurately capture market expectations for long-term natural-gas prices. Mr. Peaco fails to consider the open interest in NYMEX Henry Hub futures contracts, which quickly falls for futures contracts further out in time. The sparsity of open interest in the out period makes these futures contracts an unreliable indicator of market expectations for long-term natural-gas prices.

Each futures trade represents the creation of a new contract and is indicative of new capital being committed to the market. Figure 2-R shows NYMEX Henry Hub natural-gas open interest as of September 11, 2017.

Figure 2-R. NYMEX Henry Hub Natural Gas Futures
Open Interest as of September 11, 2017



This figure shows that open interest is greater in the near term and significantly lower in the long term. For instance, in 2018 open contracts average over 43,200. By 2023, open contracts average just over 2,600—approximately six percent of the open interest observed for 2018 contracts. The concentration in the earlier futures indicates the market is deeper and stronger in the near term because fewer market participants are willing to commit capital required to enter and maintain long-term contracts.

There are very few contracts supporting NYMEX Henry Hub natural-gas-futures prices over the period in which Mr. Peaco claims the market outlook most closely aligns with the company's low natural-gas price forecast (*i.e.*, beyond 2024). Contracts with greater open interest more accurately represent a market consensus of where spot prices are likely to trade. Long-term prices are shaped by a handful of participants who are lightly committed. These participants are basing their decisions on highly imperfect data. Short-term prices are shaped by a large field of market participants, who commit far more capital because there is more transparency around the conditions and variables that can impact prices.

Q. Has the DPU previously commented on the accuracy of the NYMEX futures contracts as a predictor for future prices?

A. Yes. I understand that, in a 2001 case, DPU discussed using NYMEX future contract prices to forecast avoided costs, but noted that the "future market is not very robust as very few trades are currently being made, thus the accuracy of the future's price is questionable." *In the Matter of Revisions to PacifiCorp's Tariff P.S.C.U. No. 43, Re: Schedule 72, Irrigation Curtailment Program Rider*, Docket No. 01-035-T04, Order (May 11, 2001).

Q. Mr. Mullins claims that the company's OFPC systematically overstates future market prices. (Mullins Direct, page 23, lines 9-15.) Please respond.

A. It is not reasonable to evaluate a forecast error for OFPCs. The company's OFPC is developed from a combination of market forwards on a given quote date and a long-term, fundamentals-based forecast as a proxy for forward prices beyond the period in which observed market forwards are not available. Forecast error is a measure of the difference between forecasted spot prices and actual spot prices. Comparing forward prices to actual spot prices is a misapplication of forecast error, because market forwards, which are used in the first 84 months of the OFPC, are observed, and not forecasted. Forward prices represent transaction prices occurring at the time of a future delivery date.

Market participants cannot transact on a spot price forecast. A spot price forecast merely represents a potential view of what prices will be at some point in the future. Market forwards reflect pricing for contracts that reflect the price, on a given quote date, at which buyers and sellers are transacting for future delivery.

Q. Mr. Mullins also claims that, "[i]f the OFPCs are reasonably accurate, one would expect PacifiCorp's price forecast to be an unbiased expectation of future spot prices." (Mullins Direct, page 27, lines 17-18.) Is this true?

A. Not necessarily. It is not strictly true that the forward prices will or should equal the expected price. Forward buyers and sellers are considering the trade-off between using a fixed forward price and simply waiting to transact at a risky spot price. To avoid arbitrage, these two have to be equal in present value, not in delivery-date value. In general, it is likely that spot prices are somewhat systematically risky, because demand for most commodities tends to move with the economy as a whole. Thus, it is unlikely that the appropriate discount rate for taking the present value of expected spot prices will be the risk-free rate that applies to discounting the forward price. For the two present values to be equal, the two future values have to be somewhat different.

Q. Mr. Mullins argues that the historical difference between the forecasted and actual spot prices indicates that there is a risk premium embedded in the OFPC. (Mullins Direct, page 28, lines 15-17.) How do you respond?

A. There may be a risk premium in the forward prices, which are used in the first 84 months of the OFPC, but that does not mean there is a risk premium further out in the forecasted period.

Moreover, Mr. Mullins' position here is contradicted by his testimony before the Oregon Commission earlier this year. In the company's annual power cost update proceeding, I understand that Mr. Mullins testified that the company's electric market transactions entered more than seven days before the settlement period (*i.e.*, hedging transactions) systematically generate customer benefits because the forward price curve is systematically *lower* than actual spot market prices. *See In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, OPUC Docket No. UE 323, ICNU/200, Mullins/8-10 (Aug. 2, 2017).

Q. Mr. Mullins claims that the Commission has expressed skepticism about the accuracy of long-term forecasting when it ordered QF contracts reduced to fifteen years. (Mullins Direct, page 32, lines 13-13.) Please respond.

A. This argument is unpersuasive. First, the company's avoided cost prices in Utah are set using the OFPC. Despite the Commission's concern over the inherent difficulty of forecasting, it has not implemented a policy requiring the company to use a lower forward price curve for avoided cost prices. Second, this argument ignores the fact that all long-term resource planning requires the use of long-term assumptions and forecasts. There is no doubt that there is uncertainty in future wholesale market prices, which is precisely the reason that the company has evaluated the Combined Projects across a range of different price-policy scenarios. And in nearly all scenarios, the Combined Projects produce net benefits for customers.

Q. Has UAE previously taken a position on price risk associated with long-term utility resource acquisitions?

A. Yes. In the same case where the Commission shortened the QF contract term, I understand that UAE's witness testified that "there is price risk associated with the acquisition of any long-term resource, including utility resources." *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA*

Power Purchase Agreements with Qualifying Facilities, Docket No. 15-035-53, Prefiled Direct Testimony of Kevin C. Higgins at lines 1465-169 (Sept. 16, 2015) (testifying on behalf of the Coalition, which included UAE). But UAE's witness argued the "price risk operates in both directions." *Id.* Thus, according to UAE, "[i]f the company's market price forecast is unbiased then the long-term price of a QF contract is as likely to be below future market prices as above them." *Id.* This prior position is fundamentally inconsistent with Mr. Mullins' testimony here that forecast prices are inherently overstated.

UAE's brief further explained that "[t]here is no way to predict whether" actual prices will be higher or lower than forecasts, but the risks are not symmetrical; the "downside risk of higher future prices is essentially limitless, while the realistic upside risk of lower future prices is relatively limited." *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities,* Docket No. 15-035-53, Post Hearing Brief of the Rocky Mountain Coalition for Renewable Energy at 8 (Dec. 9, 2015) (internal quotations omitted). Again, this prior UAE position undercuts Mr. Mullins' testimony here that forecast prices are consistently excessive. Moreover, given that the benefits of the Combined Projects increase as forecast natural-gas prices increase, UAE's prior position bolsters the case in favor of the Combined Projects.

Q. Based on the historical forecasting error, Mr. Mullins claims that the economic benefits of the Combined Projects may be overstated by approximately $411.2 million. (Mullins Direct, page 30, lines 3-12.) Is this a reasonable claim?

A. No. As I stated above, it is not reasonable to evaluate a forecast error for OFPCs, and therefore, it is not appropriate to apply an erroneous forecast error metric to long-term price assumptions. It is reasonable to assess a range of market outcomes, and this is precisely what the company has done by analyzing low and high natural-gas price scenarios that are based on recent forecasts developed by reputable third-party experts.

Q. Mr. Mullins further claims that two gas hedging contracts entered into in 2012 have been harmful to customers. (Mullins Direct, page 34, lines 15-16.) How do you respond?

A. I disagree. Mr. Mullins inappropriately reviews the performance of these two natural-gas hedges as financial trades. A financial trade is executed based on a speculative market view to earn a favorable return. A hedge is made to limit exposure to market volatility, not to earn a favorable return. The value of a hedge is not based on the fixed-price exposure of the hedge, but its effectiveness in limiting exposure to volatility in spot market prices. The effectiveness of these hedge transactions has no relevance to the validity of the company's OFPC, which reflects the best and unbiased representation of future market conditions available at the time the OFPC is produced, and has no relevance to the economic analysis of the Combined Projects.

Q. Mr. Hayet criticizes the company for updating the modeling assumptions for the Combined Projects without also updating modeling assumptions related to competing resource options, like solar resources. (Hayet Direct, lines 193-205). How do you respond?

A. As described above, the results of the 2017S RFP were used as a sensitivity in the selection of the shortlist for the 2017R RFP. Thus, the cost-and-performance assumptions related to solar resources have been fully updated commensurate with the updated modeling assumptions for the Combined Projects.

Q. Mr. Hayet was concerned that the 2017S results used in the sensitivity analysis may be incomplete because the solar RFP is still pending. (Hayet Direct, lines 675-677.) How do you respond?

A. While the 2017S RFP has not yet concluded, the data used in the company's solar sensitivities are tied to bids from a competitive solicitation process with robust market participation. Cost-and-performance assumptions used in the company's solar sensitivities are taken directly from this solicitation, which is being implemented with the oversight of an IE who has found that the process is being conducted in a clear and transparent manner. While the company has not established a final shortlist from the 2017S RFP, the sensitivity studies that rely on bids submitted into the RFP are not incomplete.

Q. Mr. Peaco claims that the company's analysis never considered smaller or larger quantities of wind resources that may be more economic than the 1,180 MW of wind included in the company's initial filing. (Peaco Direct, lines 410-415.) How do you respond?

A. Mr. Peaco is wrong. The company's portfolio development process used to evaluate the results of the 2017R RFP performed the exact analysis Mr. Peaco claims is lacking. As described in my supplemental direct testimony, the portfolio-development process allowed the SO model to select from any of the bids submitted to the 2017R RFP, which allowed the SO model to select smaller or larger quantities of wind. Ultimately, the model selected 1,170 MW of wind capacity as the least-cost bid portfolio based on the cost-and-performance of each bid.

Q. Mr. Peaco claims that the expected customer benefits are modest relative to the overall project costs and that there is very little certainty that customers will see significant, if any, cost savings. (Peaco Direct, line 316-318.) Mr. Hayet criticizes the Combined Projects because, under most scenarios, he claims they present modest benefits relative to the company's total revenue requirement. (Hayet Direct, lines 284-297.) Please respond.

A. First, Mr. Peaco mischaracterizes the relationship between the cost and benefits of the Combined Projects by comparing the up-front investment cost to the *net* benefits of the project. This artificially makes it appear that customer benefits are relatively small in relation to the investment required to deliver those benefits, when in fact, the gross benefits from the projects are actually greater than total project costs.

For instance, in the updated economic analysis, the PVRR(d) results calculated from the change in system costs through 2050 assuming medium natural-gas and medium CO_2 prices show a $177 million *net* customer benefit from the Combined Projects. This is based on present-value project costs, including changes to run-rate operating costs, totaling $1.47 billion. The present value of customer benefits, including federal PTC benefits, for this price-policy scenario is $1.65 billion, which is $177 million greater than the present value of project costs. In fact, the present value of customer benefits among all nine price-policy scenarios ranges between $1.30 billion and $2.06 billion. In nearly all scenarios, the present value of customer benefits exceed the present value of customer costs.

Second, the fact the total expected benefits are small relative to the company's total revenue requirement means little in this case. It is hard to imagine a resource decision that would provide customer benefits comparable to the total revenue requirement, which is apparently the metric Mr. Hayet has chosen to measure the reasonableness of the benefits.

Q. Mr. Mullins claims the company used supplemental GRID studies to develop unrealistic assumptions that are a "key driver in the economic benefits" of the Combined Projects. (Mullins Direct, page 41, line 7-14.) Is this true?

A. No. Contrary to Mr. Mullins' claim, the company's economic analysis supporting the Combined Projects does not include any assumptions derived from the supplemental GRID studies referenced by Mr. Mullins. The GRID studies and assumptions referred to by Mr. Mullins were used in the 2017 IRP, but not in the economic analysis included in this case.

Q. Does Mr. Mullins criticize the company's wind-integration charge assumptions used in the economic analysis supporting the Combined Projects?

A. Yes. Mr. Mullins notes that the company's wind-integration charge assumed in the economic analysis supporting the Combined Projects is \$0.63/MWh, when it estimated an integration cost of \$2.35/MWh in 2014. (Mullins Direct, page 50, lines 12-19.)

Q. Please respond.

A. The change in regulation-reserve costs is attributable to lower market prices, transmission congestion as a result of sizeable increases in solar capacity in the company's portfolio, and expanding the pool of regulation-reserve resources to include 30-minute ramping capability, none of which are disputed by Mr. Mullins. Thus, the wind-integration cost assumptions developed in the company's 2017 IRP are the most accurate estimate available.

Q. Mr. Peaco alleges that because there is no current price on carbon emissions, the scenarios with zero CO_2 price may be the most likely outcome. (Peaco Direct, lines 765-772.) Do you agree?

A. No. It is not reasonable to conclude that today's policy environment is the best indicator of the policy environment we can expect over the next three decades. It is even more unreasonable to dismiss the results of scenarios developed to quantify the economic impact of potential environmental policy outcomes that could impute a financial cost on CO_2 emissions at some point over the next three decades. While it is possible that no such policy will materialize, as contemplated in certain price-policy scenarios, it does not mean that given the current policy environment, it is the most likely scenario.

Q. Mr. Peaco claims that there is a production risk associated with the Wind Projects that impact customer benefits. (Peaco Direct, lines 979-982.) How has the company mitigated this risk?

A. Mr. Peaco does not testify that the company's wind-generation forecasts are invalid. Mr. Peaco simply asserts a potential risk to the overall economics if wind-generation output is reduced. This one-sided risk assessment fails to quantify the potential upside benefits if wind generation exceeds the assumed forecast used in the economic analysis. The company retained an independent expert to study and confirm the reasonableness of its capacity factor assumptions for specific projects bid into the 2017R RFP, and the findings of this review have been reflected in the economic analysis of specific proposals.

Q. Mr. Mullins argues that projected oversupply conditions in the West pose a risk to the Combined Projects that was not considered by the company. (Mullins Direct, page 19, lines 9-14.) Was this considered?

A. The company is aware of the development of renewable resources across the West. However, oversupply conditions are driven by the correlation between large numbers of intermittent renewable resources. For instance, wind resources in the Columbia River Gorge are often either mostly on or mostly off, with appreciable impacts on market prices in both directions. Similarly, solar resources across the West are strongly correlated with the position of the sun and thus each other, and likewise impact market prices in both directions.

While wind resources in Wyoming are correlated with each other, they are not strongly correlated with wind resources in the Columbia River Gorge or solar resources. The correlation of the proposed resources with the rest of the wind in the company's portfolio is already accounted for in the company's analysis, and the expected overall impact of renewable resource additions in the West is accounted for in the company's OFPC. Thus, the company's economic analysis reasonably accounts for potential oversupply conditions applicable to the proposed resources.

Moreover, the majority of the benefits associated with the Combined Projects are a result of fuel savings at PacifiCorp's plants, rather than market transactions based on the OFPC, particularly in the first few years. The costs associated with the company's fuel supply are less likely to be impacted by oversupply conditions in the manner suggested by Mr. Mullins.

Q. Mr. Hayet, Mr. Mullins, and Dr. Zenger also point out the risk associated with federal tax reform. (Mullins Direct, page 38, lines 14-19; Hayet Direct, pages 15-21; Zenger Direct, lines 272-274.) Has the risk associated with changes to the federal tax code been largely resolved?

A. Yes. The company's updated economic analysis described in my supplemental direct testimony accounts for the reduction in the federal income tax rate. And, despite the lower tax rate, the Combined Projects remain economic and the benefits have actually increased from the estimated benefits in the company's direct filing.

Q. Mr. Peaco questions the company's methodology for calculating the extended economic benefits beyond the 20-year study period used in the 2017 IRP. (Peaco Direct, lines 382-389.) Mr. Hayet also criticizes the calculation of extended benefits. (Hayet Direct, lines 593-594.) How do you respond?

A. The company's extrapolation methodology reasonably used the aggregate system benefits derived from the SO model and PaR over the period 2028 through 2036 (after the Dave Johnston plant retires). These data, based on how the Combined Projects affect forecasted system costs, are a reasonable proxy for projected long-term benefits associated with the Combined Projects. Mr. Peaco's criticism of this methodology simply states that the company's approach "can yield results that are problematic due to the timing of new resource additions[.]" (Peaco Direct, lines 386-387.) Mr. Peaco never explains with those problematic results are, or even if they occurred. Mr. Peaco's criticism is without merit.

Q. Mr. Hayet also argues that the benefits reflected in the repowering sensitivity are likely overstated. (Hayet Direct, lines 633-637.) What is the basis for Mr. Hayet's claim?

A. Mr. Hayet claims that the company did not provide any analysis that the benefits of the Combined Projects would increase significantly when combined with repowering and measured through 2050. Mr. Hayet argues that the methodology the company used in the repowering docket to model the customer benefits from 2037 to 2050 overstates the value of the incremental generation from the repowered facilities because there is no reason to expect the value of the incremental energy before 2037 (when repowering will produce 550 GWh) will be a reasonable proxy for the value after 2037 (when repowering will produce 3,300 GWh).

Q. Please respond.

A. The updated repowering sensitivity performed above demonstrates that the benefits of the Combined Project increase in combination with the repowering project when measured through 2036. Thus, without the extrapolation that Mr. Hayet criticizes, repowering increases customer benefits by $171 million under the medium natural-gas price, medium CO_2 price scenario, and by $159 million under the low natural-gas price, zero CO_2 price scenario as measured by risk-adjusted PaR results.

Q. Mr. Mullins claims that the use of the levelized fixed cost for the Transmission Projects understates the total costs because the transmission assets have longer useful lives than the 20-year study period used to evaluate the economic benefits of the Combined Projects. (Mullins Direct, pages 48-49.) Mr. Peaco makes a similar argument. (Peaco Direct, lines 367-379.) How do you respond?

A. First, Mr. Mullins acknowledges that levelized costs are regularly used to evaluate different generation resources with different lives. But Mr. Mullins claims that the use of levelized costs is not appropriate when comparing transmission assets because transmission lines do not produce electricity. Mr. Mullins provides no further explanation and, on its face, this argument makes no sense. If levelized costs are a reasonable metric for comparing competing resources with different useful lives, there is no reason to arbitrarily exclude transmission resources.

Second, Mr. Peaco and Mr. Mullins both claim that the company's economic analysis understates the total costs of the Transmission Projects because the economic analysis does not cover the 62-year useful life of the Transmission Projects. But, as Mr. Peaco concedes, customers will receive the benefits of the Transmission Projects beyond the study period used in this case.

Q. Mr. Peaco argues that a relatively small reduction in the amount of wind resources that the company acquires will largely eliminate the customer benefits of the Combined Projects. (Peaco Direct, lines 582-585.) How do you respond?

A. The company has established its final shortlist from the 2017R RFP and is on track to execute definitive agreements with winning bidders by mid-April 2018. At this stage, the amount of new wind resource capacity that maximizes customer benefits has been established.

Q. Mr. Davis also claims that the Wind Projects could add to the existing constraints on the transmission system and require the uneconomic curtailment of existing thermal resources. (Davis Direct, lines 220-231.) How do you respond?

A. Incremental energy from the Wind Projects could contribute to congestion and require redispatch of other system resources. Redispatch can reduce NPC benefits at times where increased congestion would restrict the otherwise economic use of other system resources to serve load or as a source for wholesale-market sales. The economic analysis summarized in my direct testimony and the updated economic analysis summarized in my supplemental direct testimony captures the cost of redispatch in the economic analysis.

CONCLUSION

Q. Please summarize the conclusions of your rebuttal testimony.

A. The results of the 2017R RFP confirm that the Combined Projects are the least-cost, least-risk resources available to serve the company's customers. The substantial volume of bids submitted into the 2017R RFP produced competitive project costs, allowing the company to obtain greater wind generating capacity at lower overall capital costs, with increased net benefits for customers. The Combined Projects show net customer benefits under all price-policy scenarios through 2036 and in seven of nine scenarios through 2050. The company's updated sensitivities further demonstrate that the Combined Projects are not displaced by solar resources that bid into the 2017S

RFP, and that the economics of the Combined Projects become more favorable when combined with wind repowering.

Despite claims to the contrary, PacifiCorp has near-term and long-term resource needs that can be partially met with heavily discounted Wind Projects that are lower cost than all other near-term and long-term resource alternatives. The Combined Projects are an element of PacifiCorp's least-cost, least-risk resource plan and there is nothing novel or unique about these resources that justifies unprecedented cost-recovery treatment that assigns all risk to the company. The company's long-standing methodology to develop its OFPC produces the best representation of future market prices for the central forecast, and alternative price-policy scenarios provide a reasonable foundation for judging risk.

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

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-1SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Rick T. Link

Summary of the Cost-and-Performance Assumptions for the Combined Projects

January 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-2SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Rick T. Link

Sapere Consulting Report —Evaluation of Wind Resource Assessments Submitted by Respondents to PacifiCorp's 2017R Renewable Resource Request for Proposals

January 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

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Rocky Mountain Power
Exhibit RMP___(RTL-3SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Testimony of Rick T. Link

Nominal Henry Hub Natural Gas Price Forecasts ($/MMBtu)

January 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Rocky Mountain Power
Exhibit RMP___(RTL-4SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Testimony of Rick T. Link

SO Model and PaR Model Annual Results ($ million)

January 2018

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($806)	($0)	$0	$1	($11)	($91)	($92)	($95)	($94)	($98)	($98)	($101)	($114)	($114)	($127)	($124)	($126)	($135)	($150)	($144)	($144)
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 DSM	($64)	$0	($0)	($1)	($2)	($3)	($4)	($5)	($7)	($9)	($9)	($11)	($11)	($11)	($11)	($11)	($11)	($11)	($11)	($11)	($10)
Change in System Fixed Cost	($81)	$0	($0)	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($32)	($22)	($12)	($27)	($27)
Net (Benefit)/Cost	($145)	($0)	($0)	($0)	($12)	($39)	($37)	($42)	($44)	($45)	($46)	($46)	($59)	($67)	($54)	$67	$57	$62	$62	$59	$65

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($795)	($0)	$0	$1	($11)	($91)	($92)	($95)	($95)	($99)	($98)	($101)	($114)	($113)	($126)	($123)	($127)	($129)	($135)	($139)	($134)
Change in Emissions	($16)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	($8)	($8)	($8)	($7)	($7)	($9)
Change in DSM	($77)	$0	($0)	($1)	($3)	($4)	($5)	($5)	($8)	($8)	($9)	($10)	($10)	($12)	($12)	($14)	($16)	($17)	($18)	($19)	($20)
Change in System Fixed Cost	($103)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($17)	($25)	($26)	($22)	($29)	($56)	($32)	($46)
Net (Benefit)/Cost	($186)	($0)	($0)	($1)	($12)	($39)	($37)	($42)	($45)	($44)	($46)	($46)	($59)	($66)	($65)	$49	$53	$46	$19	$44	$37

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($851)	($0)	$0	$0	($13)	($93)	($94)	($97)	($98)	($102)	($105)	($113)	($135)	($142)	($143)	($131)	($129)	($148)	($157)	($131)	($118)
Change in Emissions	($136)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($18)	($16)	($21)	($36)	($52)	($57)	($44)	($44)	($41)	($56)
Change in DSM	($27)	$0	$0	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($3)	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($8)	($9)
Change in System Fixed Cost	($89)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($21)	($21)	($20)	($24)	($17)	($41)	($42)
Net (Benefit)/Cost	($297)	($0)	$0	($0)	($12)	($38)	($37)	($41)	($43)	($43)	($56)	($68)	($89)	($111)	($102)	$13	$13	$9	$12	$19	$21

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($978)	($0)	$0	$1	($12)	($97)	($99)	($102)	($105)	($116)	($115)	($120)	($133)	($148)	($166)	($181)	($184)	($191)	($204)	($181)	($146)
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 DSM	($43)	$0	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($5)	($6)	($7)	($7)	($8)	($9)	($9)	($9)	($9)	($9)
Change in System Fixed Cost	($92)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($20)	($20)	($17)	($22)	$11	($43)	($94)
Net (Benefit)/Cost	($306)	($0)	($0)	($0)	($12)	($44)	($44)	($47)	($52)	($58)	($59)	($59)	($74)	($98)	($91)	$12	$16	$9	$34	$8	($2)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($906)	($0)	$0	$0	($13)	($97)	($100)	($102)	($106)	($117)	($115)	($119)	($133)	($149)	($170)	($187)	($190)	($175)	($160)	($87)	($8)
Change in Emissions	($10)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($3)	($5)	($5)	($5)	($4)	($2)
Change in DSM	($41)	$0	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($5)	($6)	($6)	($7)	($6)	($8)	($8)	($9)	($9)	($9)	($9)
Change in System Fixed Cost	($193)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($17)	($44)	($69)	($151)	($247)
Net (Benefit)/Cost	($343)	($0)	$0	($0)	($12)	($44)	($44)	($47)	($53)	($59)	($59)	($59)	($74)	($98)	($100)	$2	$5	($2)	($8)	($10)	($19)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($868)	($0)	$0	$1	($13)	($92)	($95)	($97)	($101)	($111)	($108)	($119)	($124)	($123)	($169)	($189)	($186)	($72)	($74)	($154)	($160)
Change in Emissions	($96)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($13)	($18)	($36)	($49)	($30)	($13)	($17)	($17)	($18)	($18)	($20)
Change in DSM	($48)	$0	($1)	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($6)	($6)	($7)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	($10)
Change in System Fixed Cost	($224)	$0	$0	$0	($0)	($9)	($9)	($10)	($13)	($13)	($13)	($14)	($14)	($25)	($25)	($26)	($27)	($147)	($148)	($73)	($75)
Net (Benefit)/Cost	($430)	($0)	($0)	($0)	($12)	($46)	($46)	($48)	($54)	($61)	($73)	($85)	($109)	($129)	($132)	($17)	($14)	($15)	($14)	($14)	($18)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($1,067)	($0)	$0	$1	($19)	($117)	($126)	($118)	($128)	($136)	($135)	($140)	($156)	($172)	($163)	($150)	($94)	($180)	($153)	($242)	($230)
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 DSM	($39)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)
Change in System Fixed Cost	($319)	$0	$0	$0	($0)	($3)	($3)	($26)	($30)	($30)	($31)	($32)	($32)	($39)	($75)	($94)	($149)	($67)	($109)	($51)	($71)
Net (Benefit)/Cost	($619)	($0)	($0)	($0)	($19)	($64)	($69)	($86)	($99)	($103)	($103)	($105)	($123)	($141)	($142)	($30)	($25)	($24)	($34)	($60)	($64)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($1,000)	($0)	$0	$1	($19)	($117)	($126)	($102)	($106)	($116)	($116)	($120)	($134)	($146)	($139)	($136)	($105)	($173)	($168)	($253)	($274)
Change in Emissions	($13)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	($4)	($3)	($6)	($6)	($9)	($10)
Change in DSM	($42)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($9)	($10)
Change in System Fixed Cost	($387)	$0	$0	$0	($0)	($3)	($3)	($47)	($51)	($52)	($53)	($54)	($55)	($62)	($95)	($108)	($141)	($71)	($84)	($35)	($28)
Net (Benefit)/Cost	($636)	($0)	($0)	($0)	($19)	($64)	($69)	($90)	($98)	($105)	($106)	($108)	($124)	($139)	($143)	($34)	($31)	($28)	($32)	($67)	($76)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($1,046)	($0)	$0	$1	($19)	($115)	($124)	($87)	($90)	($99)	($99)	($102)	($116)	($131)	($149)	($203)	($203)	($191)	($232)	($298)	($311)
Change in Emissions	($64)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($8)	($11)	($15)	($18)	($10)	($22)	($19)	($26)	($28)	($28)
Change in DSM	($39)	$0	($1)	($1)	($1)	($1)	($1)	($3)	($4)	($4)	($4)	($5)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($10)
Change in System Fixed Cost	($352)	$0	$0	$0	($0)	($6)	($6)	($64)	($68)	($70)	($71)	($73)	($74)	($74)	($75)	($46)	($39)	($59)	($45)	$6	$4
Net (Benefit)/Cost	($696)	($0)	($0)	($0)	($19)	($65)	($70)	($93)	($100)	($105)	($111)	($116)	($135)	($149)	($146)	($45)	($46)	($46)	($76)	($89)	($100)

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($733)	$0	$0	$1	($12)	($85)	($86)	($88)	($87)	($91)	($89)	($89)	($99)	($103)	($110)	($113)	($116)	($120)	($132)	($132)	($132)
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	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($3)
Change in DSM	($71)	$0	($0)	($1)	($3)	($3)	($4)	($6)	($8)	($10)	($10)	($12)	($12)	($12)	($12)	($12)	($12)	($12)	($12)	($12)	($11)
Change in Deficiency	($8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($3)	($3)	($6)	($2)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($80)	$0	($0)	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($32)	($22)	($12)	($27)	($27)
Net (Benefit)/Cost	($104)	$0	($0)	($1)	($13)	($35)	($33)	($38)	($40)	($41)	($41)	($37)	($48)	($60)	($44)	$70	$61	$70	$70	$65	$69

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($717)	$0	$0	$1	($11)	($85)	($85)	($88)	($87)	($91)	($89)	($89)	($99)	($102)	($109)	($111)	($113)	($114)	($116)	($122)	($116)
Change in Emissions	($25)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($9)	($10)	($12)	($14)	($12)	($13)
Change in VOM	($26)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($2)	($6)	($6)	($6)	($7)	($7)	($7)	($7)
Change in DSM	($85)	$0	($0)	($2)	($3)	($4)	($5)	($6)	($8)	($9)	($10)	($11)	($11)	($13)	($14)	($15)	($17)	($19)	($20)	($20)	($22)
Change in Deficiency	$26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	$2	$13	$13	$18	$15	$13	$9
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($103)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($17)	($25)	($26)	($22)	($29)	($56)	($32)	($46)
Net (Benefit)/Cost	($124)	$0	($0)	($1)	($13)	($36)	($34)	($38)	($40)	($40)	($41)	($37)	($48)	($59)	($58)	$65	$71	$69	$38	$59	$50

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246

Change in NPC	($775)	$0	$0	$0	($13)	($87)	($87)	($90)	($90)	($95)	($96)	($99)	($114)	($118)	($126)	($127)	($129)	($131)	($135)	($118)	($118)
Change in Emissions	($149)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($28)	($35)	($44)	($46)	($48)	($50)	($53)	($45)	($45)
Change in VOM	($16)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($4)	($2)	($2)
Change in DSM	($30)	$0	$0	($0)	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($6)	($9)	($10)
Change in Deficiency	($5)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($1)	($3)	($3)	($3)	($1)	($1)	($1)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($89)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($21)	($21)	($20)	($24)	($17)	($41)	($42)
Net (Benefit)/Cost	($258)	$0	$0	($0)	($12)	($34)	($32)	($36)	($37)	($38)	($51)	($59)	($82)	($105)	($98)	$16	$17	$15	$19	$24	$25

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($886)	$0	$0	$1	($12)	($91)	($92)	($94)	($98)	($111)	($108)	($110)	($125)	($133)	($146)	($155)	($159)	($167)	($179)	($161)	($126)
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	($21)	$0	$0	$0	($0)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($3)	($3)	($3)	($5)	($5)	($3)	($3)
Change in DSM	($47)	$0	($1)	($1)	($2)	($2)	($4)	($4)	($4)	($4)	($5)	($6)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($10)
Change in Deficiency	($6)	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	($2)	($3)	($5)	($0)	($5)	($2)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($92)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($20)	($20)	($17)	($22)	$11	($43)	($94)
Net (Benefit)/Cost	($246)	$0	($0)	($1)	($13)	($40)	($39)	($42)	($47)	($56)	($55)	($53)	($69)	($88)	($77)	$31	$33	$27	$48	$22	$11

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($838)	$0	$0	$0	($13)	($91)	($92)	($94)	($100)	($113)	($109)	($111)	($127)	($138)	($154)	($164)	($169)	($156)	($142)	($86)	($12)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($8)	($9)	($5)	($2)
Change in VOM	($19)	$0	$0	$0	($0)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($1)
Change in DSM	($44)	$0	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($5)	($7)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($9)
Change in Deficiency	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($3)	($5)	($4)	($6)	($1)	$2
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($193)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($17)	($44)	($69)	($151)	($247)
Net (Benefit)/Cost	($311)	$0	$0	($0)	($13)	($40)	($39)	($41)	($50)	($58)	($56)	($54)	($71)	($92)	($92)	$15	$14	$6	($4)	($14)	($23)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($786)	$0	$0	$1	($12)	($86)	($87)	($89)	($94)	($106)	($102)	($104)	($118)	($127)	($143)	($153)	($152)	($69)	($71)	($135)	($135)
Change in Emissions	($107)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($19)	($28)	($34)	($37)	($34)	($37)	($17)	($18)	($28)	($30)
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($1)	($1)	($2)	($2)
Change in DSM	($52)	$0	($1)	($1)	($2)	($3)	($4)	($4)	($4)	($5)	($7)	($7)	($8)	($9)	($10)	($10)	($10)	($10)	($10)	($10)	($10)
Change in Deficiency	($7)	$0	$0	($0)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	($2)	($2)	($2)	($3)	($3)	($4)	($9)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($224)	$0	$0	$0	($0)	($9)	($9)	($10)	($13)	($13)	($13)	($14)	($14)	($25)	($25)	($26)	($27)	($147)	($148)	($73)	($75)
Net (Benefit)/Cost	($388)	$0	($0)	($1)	($13)	($42)	($41)	($43)	($50)	($58)	($66)	($73)	($98)	($121)	($117)	($7)	($6)	($16)	($16)	($11)	($17)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($923)	$0	$0	$1	($18)	($110)	($116)	($107)	($112)	($117)	($115)	($116)	($132)	($147)	($140)	($130)	($85)	($149)	($124)	($198)	($189)
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	($18)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($4)
Change in DSM	($42)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($9)
Change in Deficiency	($12)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	($2)	($4)	($4)	($13)	($18)	$0	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($319)	$0	$0	$0	($0)	($3)	($3)	($26)	($30)	($30)	($31)	($32)	($32)	($39)	($75)	($94)	($149)	($67)	($109)	($51)	($71)
Net (Benefit)/Cost	($509)	$0	($0)	($1)	($18)	($59)	($61)	($77)	($86)	($87)	($86)	($84)	($100)	($118)	($123)	($16)	($21)	($9)	($26)	($21)	($31)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($869)	$0	$0	$1	($18)	($110)	($116)	($93)	($95)	($101)	($99)	($99)	($113)	($125)	($120)	($117)	($90)	($146)	($142)	($210)	($226)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($5)	($4)	($8)	($8)	($12)	($15)
Change in VOM	($16)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($1)	($2)	($2)	($3)	($4)
Change in DSM	($45)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($6)	($7)	($7)	($8)	($8)	($8)	($9)	($9)	($10)	($11)
Change in Deficiency	($10)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($2)	($1)	($13)	($16)	($0)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($387)	$0	$0	$0	($0)	($3)	($3)	($47)	($51)	($52)	($53)	($54)	($55)	($62)	($95)	($108)	($141)	($71)	($84)	($35)	($28)
Net (Benefit)/Cost	($539)	$0	($0)	($1)	($18)	($59)	($61)	($84)	($89)	($92)	($92)	($90)	($104)	($120)	($128)	($21)	($21)	($18)	($28)	($31)	($41)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($898)	$0	$0	$1	($18)	($108)	($114)	($81)	($81)	($86)	($84)	($83)	($95)	($110)	($126)	($186)	($165)	($158)	($190)	($239)	($246)
Change in Emissions	($94)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($13)	($17)	($20)	($23)	($17)	($31)	($30)	($34)	($40)	($41)
Change in VOM	($18)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($4)	($3)	($2)	($3)	($4)	($4)
Change in DSM	($42)	$0	($1)	($1)	($1)	($1)	($1)	($3)	($5)	($5)	($5)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($10)	($11)
Change in Deficiency	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	($2)	($1)	($13)	($5)	($2)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($352)	$0	$0	$0	($0)	($6)	($6)	($64)	($68)	($70)	($71)	($73)	($74)	($74)	($75)	($46)	($39)	($59)	($45)	$6	$4
Net (Benefit)/Cost	($605)	$0	($0)	($1)	($18)	($60)	($62)	($89)	($93)	($95)	($101)	($105)	($123)	($135)	($132)	($41)	($21)	($40)	($50)	($48)	($58)

Rocky Mountain Power
Exhibit RMP___(RTL-5SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results ($ million)

January 2018

Exhibit RMP__(RTL-5SD)

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)	$0
System Impacts																																			
NPC	($1,033)	$0	$1	($12)	($85)	($86)	($88)	($87)	($91)	($89)	($89)	($99)	($103)	($110)	($113)	($116)	($120)	($132)	($132)	($132)	($130)	($133)	($136)	($139)	($116)	($119)	($121)	($124)	($127)	($130)	($132)	($136)	($138)	($141)	$0
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($140)	($0)	($1)	($3)	($5)	($6)	($8)	($10)	($12)	($13)	($14)	($14)	($15)	($17)	($19)	($17)	($17)	($21)	($17)	($18)	($19)	($20)	($20)	($21)	($17)	($17)	($18)	($18)	($19)	($19)	($20)	($20)	($20)	($21)	$0
System Fixed Costs	($131)	($0)	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($32)	($22)	($12)	($27)	($27)	($22)	($22)	($23)	($24)	($20)	($20)	($21)	($21)	($21)	($22)	($22)	($23)	($23)	($24)	$0
Net System Impacts	($1,304)	($0)	($1)	($15)	($93)	($95)	($100)	($103)	($109)	($108)	($110)	($120)	($137)	($146)	($150)	($165)	($160)	($166)	($176)	($177)	($171)	($175)	($179)	($183)	($153)	($156)	($160)	($164)	($167)	($171)	($174)	($179)	($182)	($186)	$0
Net (Benefit)/Cost	$169	($0)	($1)	$6	$66	$51	$31	$13	$1	($7)	($12)	($31)	($50)	($40)	$68	$51	$54	$46	$34	$32	$37	$32	$27	$22	$40	$36	$33	$29	$27	$26	$26	$28	$25	($412)	$0

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,003)	$0	$0	$1	($11)	($85)	($85)	($88)	($87)	($91)	($89)	($89)	($99)	($102)	($109)	($111)	($113)	($114)	($116)	($122)	($116)	($124)	($127)	($130)	($133)	($111)	($113)	($116)	($119)	($121)	($124)	($126)	($130)	($132)	($135)
Emissions	($46)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($9)	($10)	($12)	($14)	($12)	($13)	($9)	($9)	($9)	($10)	($8)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($10)	($10)
Other Variable Costs	($119)	$0	($0)	($2)	($3)	($6)	($7)	($8)	($11)	($11)	($13)	($14)	($14)	($16)	($18)	($9)	($11)	($7)	($11)	($15)	($20)	($15)	($15)	($16)	($16)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)
System Fixed Costs	($173)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($17)	($25)	($26)	($22)	($29)	($56)	($32)	($46)	($30)	($31)	($32)	($32)	($27)	($28)	($28)	($29)	($29)	($30)	($31)	($32)	($32)	($33)
Net System Impacts	($1,341)	$0	($0)	($1)	($15)	($93)	($95)	($100)	($104)	($108)	($108)	($109)	($119)	($135)	($160)	($155)	($155)	($162)	($197)	($181)	($196)	($178)	($182)	($186)	($191)	($159)	($163)	($166)	($171)	($174)	($178)	($182)	($186)	($190)	($194)
Net (Benefit)/Cost	$133	$0	($0)	($1)	$6	$66	$51	$31	$13	$2	($7)	($12)	($30)	($48)	($55)	$63	$61	$52	$15	$28	$13	$29	$25	$20	$14	$33	$30	$26	$22	$20	$18	$18	$21	$17	($419)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,096)	$0	$0	$0	($13)	($87)	($87)	($90)	($90)	($95)	($96)	($99)	($114)	($118)	($126)	($127)	($129)	($131)	($135)	($118)	($118)	($139)	($142)	($145)	($149)	($124)	($127)	($130)	($133)	($135)	($138)	($142)	($145)	($148)	($151)
Emissions	($261)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($28)	($35)	($44)	($46)	($48)	($50)	($53)	($45)	($45)	($48)	($49)	($50)	($52)	($43)	($44)	($45)	($46)	($47)	($48)	($49)	($50)	($51)	($53)
Other Variable Costs	($77)	$0	$0	($0)	($1)	($3)	($4)	($4)	($5)	($5)	($6)	($6)	($6)	($7)	($10)	($10)	($11)	($11)	($11)	($12)	($15)	($11)	($11)	($12)	($12)	($10)	($10)	($10)	($11)	($11)	($11)	($11)	($12)	($12)	($12)
System Fixed Costs	($146)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($21)	($21)	($20)	($24)	($17)	($41)	($42)	($25)	($25)	($26)	($27)	($22)	($23)	($23)	($24)	($24)	($25)	($25)	($26)	($26)	($27)
Net System Impacts	($1,579)	$0	$0	($0)	($14)	($92)	($94)	($98)	($101)	($106)	($119)	($132)	($154)	($181)	($200)	($204)	($208)	($215)	($216)	($216)	($221)	($223)	($228)	($233)	($239)	($199)	($204)	($208)	($214)	($218)	($223)	($228)	($234)	($238)	($243)
Net (Benefit)/Cost	($105)	$0	$0	($0)	$7	$67	$52	$33	$16	$5	($17)	($34)	($64)	($95)	($95)	$14	$8	($1)	($4)	($7)	($12)	($16)	($22)	($27)	($34)	($7)	($12)	($16)	($21)	($24)	($26)	($28)	($26)	($31)	($468)

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,272)	$0	$0	$1	($12)	($91)	($92)	($94)	($98)	($111)	($108)	($110)	($125)	($133)	($146)	($155)	($159)	($167)	($179)	($161)	($126)	($167)	($171)	($175)	($179)	($149)	($153)	($156)	($160)	($163)	($167)	($170)	($175)	($178)	($182)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($110)	$0	($1)	($1)	($2)	($4)	($6)	($6)	($7)	($7)	($8)	($9)	($9)	($11)	($13)	($15)	($17)	($15)	($19)	($15)	($15)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($151)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($20)	($20)	($17)	($22)	$11	($43)	($94)	($26)	($26)	($27)	($28)	($23)	($24)	($24)	($25)	($25)	($26)	($26)	($27)	($28)	($28)
Net System Impacts	($1,533)	$0	($0)	($1)	($15)	($98)	($101)	($103)	($111)	($124)	($123)	($125)	($140)	($164)	($178)	($190)	($193)	($203)	($187)	($218)	($235)	($209)	($213)	($218)	($224)	($187)	($191)	($195)	($200)	($204)	($208)	($213)	($218)	($222)	($227)
Net (Benefit)/Cost	($60)	$0	($0)	($1)	$6	$62	$45	$27	$6	($14)	($22)	($27)	($51)	($77)	($73)	$28	$23	$11	$25	($9)	($27)	($1)	($7)	($12)	($19)	$6	$2	($3)	($7)	($10)	($12)	($13)	($11)	($15)	($453)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)

Exhibit RMP__(RTL-5SD)

Estimated Annual Revenue Requirement Results ($ million)

PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214
System Impacts																		
NPC	($1,181)	$0	$0	$0	($13)	($91)	($92)	($94)	($100)	($113)	($109)	($111)	($127)	($138)	($154)	($164)	($169)	($156)
Emissions	($31)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($8)
Other Variable Costs	($103)	$0	$0	($1)	($2)	($4)	($6)	($6)	($7)	($7)	($8)	($10)	($9)	($11)	($12)	($15)	($17)	($16)
System Fixed Costs	($337)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($17)	($44)
Net System Impacts	($1,651)	$0	$0	($0)	($15)	($98)	($100)	($103)	($113)	($126)	($124)	($126)	($143)	($168)	($194)	($206)	($211)	($225)
Net (Benefit)/Cost	($177)	$0	$0	($0)	$6	$62	$46	$28	$4	($15)	($22)	($29)	($53)	($82)	($89)	$12	$5	($11)

PTCs - Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																	
NPC	($142)	($86)	($12)	($148)	($152)	($155)	($159)	($133)	($136)	($139)	($142)	($145)	($148)	($151)	($155)	($158)	($162)
Emissions	($9)	($5)	($2)	($6)	($6)	($6)	($6)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)
Other Variable Costs	($18)	($13)	($8)	($15)	($15)	($15)	($16)	($13)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($16)	($16)
System Fixed Costs	($69)	($151)	($247)	($62)	($64)	($65)	($67)	($56)	($57)	($58)	($60)	($61)	($62)	($63)	($65)	($66)	($68)
Net System Impacts	($239)	($255)	($269)	($231)	($236)	($242)	($248)	($207)	($211)	($216)	($222)	($226)	($231)	($236)	($242)	($246)	($252)
Net (Benefit)/Cost	($27)	($45)	($61)	($24)	($30)	($36)	($43)	($14)	($19)	($24)	($29)	($32)	($35)	($36)	($35)	($39)	($477)

Exhibit RMP__(RTL-5SD)

Estimated Annual Revenue Requirement Results ($ million)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,107)	$0	$0	$1	($12)	($86)	($87)	($89)	($94)	($106)	($102)	($104)	($118)	($127)	($143)	($153)	($152)	($69)	($71)	($135)	($135)	($139)	($142)	($145)	($149)	($124)	($127)	($130)	($133)	($136)	($139)	($142)	($145)	($148)	($151)
Emissions	($184)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($19)	($28)	($34)	($37)	($34)	($37)	($17)	($18)	($28)	($30)	($33)	($34)	($35)	($36)	($30)	($31)	($31)	($32)	($33)	($33)	($34)	($35)	($36)	($36)
Other Variable Costs	($112)	$0	($1)	($1)	($2)	($5)	($6)	($6)	($7)	($8)	($9)	($9)	($10)	($12)	($14)	($14)	($15)	($14)	($14)	($16)	($22)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($371)	$0	$0	$0	($0)	($9)	($9)	($10)	($13)	($13)	($13)	($14)	($14)	($25)	($25)	($26)	($27)	($147)	($148)	($73)	($75)	($64)	($65)	($66)	($68)	($57)	($58)	($59)	($61)	($62)	($63)	($65)	($67)	($68)	($69)
Net System Impacts	($1,774)	$0	($0)	($1)	($15)	($100)	($102)	($105)	($113)	($126)	($134)	($145)	($169)	($198)	($219)	($227)	($231)	($247)	($251)	($252)	($262)	($252)	($257)	($263)	($270)	($225)	($230)	($235)	($241)	($246)	($251)	($257)	($263)	($268)	($274)
Net (Benefit)/Cost	($301)	$0	($0)	($1)	$6	$60	$43	$26	$3	($16)	($33)	($48)	($80)	($111)	($114)	($9)	($15)	($33)	($40)	($42)	($54)	($44)	($51)	($57)	($65)	($32)	($38)	($43)	($48)	($52)	($55)	($57)	($56)	($61)	($499)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,290)	$0	$0	$1	($18)	($110)	($116)	($107)	($112)	($117)	($115)	($116)	($132)	($147)	($140)	($130)	($85)	($149)	($124)	($198)	($189)	($159)	($162)	($166)	($170)	($142)	($145)	($148)	($152)	($155)	($158)	($162)	($166)	($169)	($173)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($108)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($7)	($8)	($7)	($8)	($8)	($9)	($10)	($13)	($13)	($23)	($28)	($12)	($16)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($512)	$0	$0	$0	($0)	($3)	($3)	($26)	($30)	($30)	($31)	($32)	($32)	($39)	($75)	($94)	($149)	($67)	($109)	($51)	($71)	($84)	($86)	($87)	($90)	($75)	($76)	($78)	($80)	($82)	($84)	($85)	($88)	($89)	($91)
Net System Impacts	($1,910)	$0	($0)	($1)	($20)	($117)	($123)	($139)	($149)	($155)	($154)	($156)	($172)	($195)	($225)	($237)	($247)	($239)	($261)	($261)	($276)	($258)	($264)	($270)	($276)	($231)	($236)	($241)	($247)	($252)	($257)	($263)	($270)	($275)	($281)
Net (Benefit)/Cost	($437)	$0	($0)	($1)	$1	$43	$23	($8)	($33)	($45)	($52)	($58)	($82)	($108)	($120)	($18)	($31)	($25)	($50)	($52)	($68)	($50)	($57)	($64)	($71)	($38)	($44)	($49)	($55)	($58)	($61)	($63)	($63)	($68)	($506)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,227)	$0	$0	$1	($18)	($110)	($116)	($93)	($95)	($101)	($99)	($99)	($113)	($125)	($120)	($117)	($90)	($146)	($142)	($210)	($226)	($155)	($158)	($162)	($166)	($139)	($142)	($145)	($149)	($151)	($155)	($158)	($162)	($165)	($169)
Emissions	($31)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($5)	($4)	($8)	($8)	($12)	($15)	($6)	($6)	($6)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)	($7)
Other Variable Costs	($108)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($7)	($7)	($7)	($8)	($8)	($9)	($10)	($12)	($11)	($24)	($28)	($14)	($18)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($587)	$0	$0	$0	($0)	($3)	($3)	($47)	($51)	($52)	($53)	($54)	($55)	($62)	($95)	($108)	($141)	($71)	($84)	($35)	($28)	($87)	($89)	($91)	($93)	($77)	($79)	($81)	($83)	($85)	($86)	($88)	($91)	($92)	($94)
Net System Impacts	($1,953)	$0	($0)	($1)	($20)	($117)	($123)	($145)	($153)	($160)	($159)	($162)	($176)	($196)	($230)	($242)	($247)	($248)	($263)	($271)	($287)	($263)	($269)	($275)	($282)	($236)	($241)	($246)	($253)	($257)	($263)	($269)	($276)	($281)	($287)
Net (Benefit)/Cost	($479)	$0	($0)	($1)	$1	$43	$23	($15)	($36)	($50)	($58)	($64)	($87)	($110)	($124)	($23)	($30)	($35)	($52)	($62)	($78)	($56)	($63)	($70)	($77)	($43)	($49)	($54)	($60)	($63)	($67)	($69)	($68)	($74)	($512)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$411	$0	$0	$0	$4	$22	$22	$22	$22	$24	$26	$27	$29	$31	$35	$39	$42	$45	$48	$51	$55	$58	$61	$65	$69	$73	$77	$81	$86	$92	$98	$106	$118	$122	$71
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,474	$0	$0	$0	$21	$159	$146	$131	$117	$110	$101	$98	$89	$87	$105	$218	$216	$214	$212	$210	$209	$207	$206	$206	$205	$193	$192	$192	$193	$194	$196	$200	$207	$207	($225)
System Impacts																																			
NPC	($1,314)	$0	$0	$1	($18)	($108)	($114)	($81)	($81)	($86)	($84)	($83)	($95)	($110)	($126)	($186)	($165)	($158)	($190)	($239)	($246)	($180)	($184)	($188)	($193)	($161)	($165)	($168)	($173)	($176)	($180)	($184)	($189)	($192)	($196)
Emissions	($163)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($13)	($17)	($20)	($23)	($17)	($31)	($30)	($34)	($40)	($41)	($30)	($31)	($31)	($32)	($27)	($28)	($28)	($29)	($29)	($30)	($31)	($32)	($32)	($33)
Other Variable Costs	($102)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($6)	($7)	($7)	($8)	($8)	($8)	($9)	($13)	($12)	($24)	($17)	($15)	($20)	($15)	($15)	($16)	($16)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)
System Fixed Costs	($480)	$0	$0	$0	($0)	($6)	($6)	($64)	($68)	($70)	($71)	($73)	($74)	($74)	($75)	($46)	($39)	($59)	($45)	$6	$4	($55)	($56)	($58)	($59)	($49)	($50)	($52)	($53)	($54)	($55)	($56)	($58)	($59)	($60)
Net System Impacts	($2,059)	$0	($0)	($1)	($20)	($117)	($123)	($150)	($156)	($163)	($169)	($177)	($195)	($212)	($234)	($262)	($246)	($271)	($285)	($288)	($304)	($280)	($287)	($293)	($300)	($251)	($256)	($262)	($269)	($274)	($280)	($286)	($294)	($299)	($305)
Net (Benefit)/Cost	($585)	$0	($0)	($1)	$1	$42	$22	($20)	($39)	($53)	($68)	($80)	($106)	($125)	($128)	($44)	($30)	($57)	($74)	($79)	($95)	($73)	($80)	($87)	($95)	($58)	($64)	($70)	($76)	($80)	($84)	($86)	($86)	($92)	($531)

Rocky Mountain Power
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct and Rebuttal Testimony of Joelle R. Steward

January 2018

Q. Please state your name, business address, and current position with Rocky Mountain Power ("Company"), a division of PacifiCorp.

A. My name is Joelle R. Steward. My business address is 1407 West North Temple, Suite 330, Salt Lake City, Utah 84116. My title is Vice President of Regulation for Rocky Mountain Power.

QUALIFICATIONS

Q. Please describe your education and professional background.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as the Regulatory Manager responsible for all regulatory filings and proceedings in Oregon. From February 2012 through May 2016, I was a Director in charge of the work for the cost of service, pricing, and regulatory operations groups for the Company. In 2016, I became the Director of Rates and Regulatory Affairs and added responsibilities for regulatory affairs for Rocky Mountain Power. In November 2017, I assumed my current position as Vice President of Regulation for Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in Idaho, Oregon, Utah, Wyoming, and Washington.

Q. Are you adopting the direct testimony of Mr. Jeffrey K. Larsen in this case?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony supports the Company's request that the Public Service Commission of Utah ("Commission") approve its significant energy resource decision for new wind resources ("Wind Projects") and voluntary energy resource decision for construction of the Aeolus-to-Bridger/Anticline line and network upgrades("Transmission Projects"), as reflected in this supplemental filing (collectively, the "Combined Projects"). In my supplemental direct testimony, I update the expected costs and benefits proposed to be recovered through the Resource Tracking Mechanism ("RTM"), associated with the Combined Projects based on the Company's 2017R Request for Proposals ("2017R RFP") final shortlist.

In my rebuttal testimony, I respond to regulatory policy and ratemaking issues raised in the direct testimonies of Division of Public Utilities ("DPU") witnesses Dr. Joni Zenger, Mr. Daniel Peaco, and Mr. David Thomson; Utah Association of Energy Users ("UAE") and Utah Industrial Electricity Consumers ("UIEC") witness Mr. Bradley Mullins; and Office of Consumer Services ("OCS") witnesses Mr. Bela Vastag and Ms. Donna Ramas.

Q. What are the key issues you address in your rebuttal testimony?

A. I address the following key issues:

- The reasonableness of allowing full recovery of the prudent costs of the Combined Projects, including a return on investment.
- How the Company's proposed RTM fairly and efficiently allows costs and benefits to be tracked through rates on a temporary basis until the next general

rate case.

Q. Please summarize your testimony.

A. The lower rate impact of the Combined Projects reflects the reduction in costs and increase in benefits in the Company's updated economic analysis provided by Company witness Mr. Rick T. Link. It also reflects the effects of federal tax reform. Overall, these changes show a reduction in revenue requirement of nearly 20 percent from the initial filing. The Company's request for resource approval and recovery through the RTM is reasonable and in the public interest. The Combined Projects are the least cost alternative to meet customers' needs today and into the future. As such, the higher standard for approval of the Combined Projects proposed by parties is inappropriate and unwarranted. The Company has also actively managed the costs of the Combined Projects through competitive solicitations, and mitigated project risks within the Company's control.

The RTM is an interim mechanism to pass the benefits of the Combined Projects to customers until the resources are incorporated into base rates through a general rate case. The only "benefit" to the Company is the opportunity to recover its reasonable and prudent costs, like any other resource investment. The Company agrees that the RTM would be consistent with the soft cap in Utah Code Ann. § 54-17-303 and reflect actual costs up to a maximum of the final estimated costs from this proceeding.

SUPPLEMENTAL DIRECT TESTIMONY

Q. Have you updated the exhibits from your direct testimony to reflect the updated economic analysis for the Combined Projects, including the Wind Projects selected to the 2017R RFP final shortlist, as reflected in this supplemental direct

filing?

A. Yes. My original exhibits have been updated and are presented as Exhibit RMP___(JRS-1SD), Exhibit RMP___(JRS-2SD), Exhibit RMP___(JRS-3SD) and Exhibit RMP___(JRS-4SD).[1] These exhibits are revised with the updated economic analysis in Mr. Link's supplemental direct testimony, which reflects results from the 2017R RFP final shortlist. The exhibits are in the same format as in the initial filing, and calculate the monthly and annual revenue requirements and the overall rate impact for the Combined Projects that would be reflected in rates, including the proposed RTM.

Q. Please provide a summary of the updates in your revised exhibits.

A. The updates include changes in Utah's allocated share of the updated Combined Projects' construction costs, return, depreciation, Production Tax Credits ("PTCs"), taxes, and operating costs and benefits. Updated net power costs associated with the 2017R RFP final shortlist, an updated load forecast, system dispatch, and revised wind generation projections have also been included in the Energy Balancing Account ("EBA") pass-through calculation. Overall these changes show a reduction in revenue requirement of nearly 20 percent from the initial filing.

Q. Does the updated revenue requirement analysis incorporate the federal income tax rate change from 35 percent to 21 percent, as passed under the Tax Act of 2017?

A. Yes. As shown in Exhibit RMP___(JRS-4SD), line 5, the consolidated federal and state income tax rate has changed from the 37.951 percent used in my direct testimony to

[1] Exhibit RMP___(JRS-1SD) is included but is the same as Exhibit RMP__(JKL-1) presented in direct testimony.

24.587 percent, reflecting the change in the federal tax rate. Also, on line 6 of Exhibit RMP___(JRS-4SD), the PTC tax gross-up factor has been updated from 1.6116 in my direct testimony to 1.3260. These changes are incorporated in the revenue requirement results shown in Exhibit RMP___(JRS-2SD) and Exhibit RMP___(JRS-3SD).

Q. In addition to the updated economic analysis, are there any additional changes to the original exhibits?

A. Yes. Exhibit RMP___(JRS-2SD) and Exhibit RMP___(JRS-3SD) incorporate a revised carrying charge rate to be applied to the RTM Deferral Balance.

Q. Please explain.

A. The RTM deferral balance carrying charge presented in my direct testimony was based on the same carrying charge rate used in the Company's EBA filings, as specified in Electric Service Schedule No. 94, which is currently 6.0 percent. As discussed further below, the Company has revised the carrying charge rate to be consistent with the Commission's Carrying Charge Order in Docket No. 17-035-T02 and Docket No. 15-035-69, which is currently 4.19 percent. Exhibit RMP___(JRS-2SD) and Exhibit RMP___(JRS-3SD) have been updated to incorporate the revised carrying charge.

Q. What is the updated estimated rate impact associated with the Combined Projects, which would be reflected in rates through the RTM, in conjunction with the EBA?

A. The Company is projecting the Combined Projects' updated annual revenue requirement impact for the years 2020 to 2023 to be in the range of ($2) million to $31 million in Utah, as shown in Table 1 of Exhibit RMP___(JRS-2SD). The net rate impact would now be less than 1.6 percent for the first full year of operation.

Q. As a result of this updated economic analysis, has the Company's proposed

ratemaking treatment for interim recovery of costs through the RTM changed?

A. No. As discussed further below, the Company continues to propose recovery of costs through the RTM in order to concurrently match benefits and costs in rates.

REBUTTAL TESTIMONY

<u>**Resource Tracking Mechanism**</u>

Q. What should the Commission consider when determining whether to approve the Company's proposed energy resource decisions and RTM?

A. The Commission must determine that the Combined Projects are in the public interest and the RTM reasonably balances the Company's and customers' interests. These findings are supported by the results of the Company's 2017 Integrated Resource Plan, and Mr. Link's direct, supplemental direct and rebuttal testimonies explaining why the Company selected the Combined Projects as the least-cost, least-risk option to provide safe and reliable electric service to customers. The Combined Projects provide substantial benefits to customers that should be matched in rates with project costs. The proposed RTM combined with a future rate case is the best way to achieve that goal.

Q. Why is the RTM necessary?

A. The RTM is designed to match all costs and benefits over a short period of time. The RTM will allow the Company to track costs and deliver benefits to customers until the next rate case, while also allowing the Company to include the Combined Projects in base rates in a single general rate case filing. The RTM enables the Company to align near-term cost drivers into one general rate case, rather than rate cases over a multiple-year period. Without the RTM, all of the zero-fuel cost energy would flow to customers through the Energy Balancing Account mechanism ("EBA"), without recovery of the benefits of the production tax credits ("PTC") or the costs that enable those benefits.

Q. Is the RTM intended to provide rate recovery over the life of the new resources?

A. No. The RTM is a short-term tracking mechanism that matches all benefits and costs until they are included in rates in the next general rate case. The RTM is not intended to be a permanent mechanism in place for the life of the Combined Projects.

Q. Ms. Ramas and Mr. Thomson recommend that the Commission reject the RTM and instead allow the Company to recover the costs of Combined Projects through a general rate case filing. (Ramas Direct, lines 129-133; Thomson Direct, lines 99-106.) Do you agree this approach is sufficient for the Combined Projects?

A. No. As both Ms. Ramas and Mr. Thomson recognize, the Company can file a general rate case using a future test year with projected data not to exceed 20 months from the proposed rate effective date.[2] Although the Company can request the use of a future test year, the Commission may not approve one, and parties, including OCS and UAE, have opposed future test years in the past.[3] Thus, it is highly uncertain whether the Company could implement the proposal to use a future test year to fully capture the costs and benefits of the Combined Projects in a single, timely general rate case, making timely cost recovery of this investment uncertain.

Q. Are there other concerns about relying on a single rate case with a future test period to recover the costs of the Combined Projects?

A. Yes. A forecast test period, as specifically suggested by Mr. Thomson, would not necessarily provide full and timely recovery of the costs. For example, Mr. Thomson suggests the Company could file a rate case July 1, 2019, using a future test period of

[2] Utah Code Ann. § 54-4-4(3).

[3] See Utah Docket No. 10-035-124, Order On Test Period (March 30, 2011).

calendar year 2020. (Thomson Direct, lines 99-103.) Since the Combined Project investment won't go into service until late in 2020, new rates using a calendar year 2020 test period would only reflect potentially one or two months of the investment using the Commission's traditional thirteen-month average rate base. The Company would need to immediately file another rate case in order to get the entire costs in rates.

Additionally, if all costs are deemed prudent, the results under either the RTM or a fully forecast rate period would be similar, however, the rate case would reflect projected costs of the Combined Projects in rates whereas the RTM would reflect actual costs, subject to the soft cap in Utah Code Ann. § 54-17-303. Therefore, the Company recommends the use of the RTM, which includes the opportunity for a prudence review of the project implementation of the expenditures before the costs are reflected in rates.

Q. Does Ms. Ramas recognize that there would be a mismatch between costs and benefits without the RTM?

A. Not specifically. However, without the RTM, capital costs would be absorbed by the Company, while a substantial portion of the benefits would automatically flow through to customers in the EBA.

Q. Do you agree that it would be reasonable to let the benefits go through the EBA without an RTM, or otherwise accounting for the corresponding costs?

A. No, the costs and benefits must be matched during the interim period. For example, it would not be reasonable to allow the Wind Projects' energy benefits to flow to customers through the EBA before the costs of the Combined Projects are reflected in rates. I continue to believe that the RTM is the most reasonable method for matching costs and benefits of the Combined Projects, but there may be reasonable ways of implementing Ms. Ramas' proposed approach. Nonetheless, the RTM would provide a bridge mechanism to allow the Company to balance the timing and test period for its next general rate case.

Q. Ms. Ramas argues that the Combined Projects, together with the Company's proposal to repower its wind fleet, are large enough investments that they should not be recovered outside of base rates, particularly because it has been so long since the Company's last general rate case. (Ramas Direct, lines 65-76.) How do you respond?

A. The Company recognizes that these are major investments and that this is a unique circumstance, which is why the Company has filed this request seeking Commission and stakeholder review of the resource opportunity. However, the Company has proposed the RTM in order to align the timing of the next general rate case in order to avoid back-to-back cases. The short-term use of the RTM does not unfairly impact customers since customers would be receiving the benefits matched with the associated costs of the projects.

Q. Ms. Ramas is also concerned that the use of the RTM will remove the Company's incentive to control costs between rate cases. (Ramas Direct, page 13, lines 295-298.) Does this concern apply to the RTM?

A. No. The Company agrees that the full costs of the Combined Projects should be subject to review before they are included in rates to verify that the Company prudently managed project implementation. The RTM does this by providing separate, annual filings that will follow the Commission process that allows for review by all interested and affected stakeholders.

Q. Ms. Ramas insists that the RTM will be overly complex in terms of matching costs and benefits. (Ramas Direct, lines 313-319.) Do you agree?

A. No. I do not agree that the RTM is overly complex. As demonstrated in my exhibits the RTM is a traditional revenue requirement calculation. This exact same calculation would need to be performed if the cost were considered in a general rate case. The RTM accomplishes the intent of the regulatory compact by matching the costs with the associated customer benefits.

Q. Mr. Mullins argues the RTM constitutes single-issue ratemaking, which he claims is "inherently unfair to ratepayers and should be avoided." (Mullins Direct, page 52, lines 15-17.) How do you respond?

A. Mr. Mullins' concerns are unfounded. Mr. Mullins argues that single-issue ratemaking is improper because it ignores the matching principle by isolating only increasing costs, without considering offsetting benefits. (Mullins Direct, page 52, lines 2-6). But the RTM is carefully designed to honor the matching principle by ensuring the costs and benefits of the Combined Project both flow through rates. Indeed, without the RTM, there will be a mismatch in that customers will receive the benefits without paying the costs.

<u>**Deferral vs. Accounting Order**</u>

Q. What is your position on Mr. Thomson's proposal that the Commission issue an accounting order to defer the costs and benefits of the Combined Projects until the next rate case, rather than approve the RTM? (Thomson Direct, page 6, lines 93-95.)

A. The RTM included in the EBA is a deferral mechanism with the deferral and amortization period more closely aligned. Under Mr. Thomson's proposal, the Commission would calculate the deferral in the same way as the RTM. Thus, the deferral of the incremental costs and benefits of the Combined Projects would be similar and the accounting treatment would essentially be the same as the RTM. However, the delay in the collections from deferring the costs of the Combined Projects, rather than implementing an annual true-up mechanism, creates several problems.

Q. Please describe the problems associated with using a deferral instead of the RTM to track the Combined Projects' costs and benefits.

A. First, the RTM ensures that costs and benefits are properly matched in the interim until the next rate case. The RTM deferral will end when Combined Projects' costs are reflected in base rates (except for the tracking of the variability of PTCs). A deferral as proposed by Mr. Thomson, on the other hand, could result in a later amortization that would increase the rate pressure on customers over and above base rate changes incorporating the investments.

Second, the RTM matches the costs and benefits so that the customers receiving the benefits are also paying the costs that generate those benefits. If the investment costs and PTCs are deferred, but the net power cost ("NPC") benefits flow through the EBA, a mismatch occurs and customers receive a windfall in the near term. This violates the matching principle for costs and benefits. Because Mr. Thomson's deferral results in a mismatch, I recommend using the RTM, which produces essentially the same result and avoids these issues. If Mr. Thomson's deferral approach is used, the NPC benefits of the zero-cost energy should be pulled out of the EBA and deferred as well.

Third, generally accepted accounting principles do not allow for the deferral of a return on investment that would be collected at some undetermined time in the future. With the RTM, the collection of the return component happens annually as part of the RTM's regular true-up process. The deferral approach would have the same total overall impact on customers; however, it would lead to complicated separate accounting, increased difficulty in auditing, and delayed inclusion of cost/benefit impacts for both customers and the Company.

Q. Mr. Thomson recommends the Commission use an accounting order "without the interest carrying charges or sur-credits." (Thomson Direct, lines 93-97.) Is this a reasonable recommendation?

A. No. Mr. Thomson does not explain the rationale for his proposal or justify its departure from established Commission precedent.

The elimination of a carrying charge, as proposed by Mr. Thomson, is unjustified. It is appropriate to apply a carrying charge to the balance of the RTM similar to the treatment for other mechanisms. As long as the Commission approves a reasonable carrying charge, however, the Company agrees to a deviation from the carrying charge used for the EBA. In Mr. Thomson's testimony, he comments that: "A reasonable carrying charge would be based on the Commission-approved carrying charge method."[4] The carrying charge in my exhibits has been updated using the Commission-approved carrying charge method rather than the carrying charge used in the EBA.

[4] Mr. Thomson Direct, lines 88-89.

Q. Why should the Commission approve the use of a mechanism to recover PTCs now, rather than in a future rate case as proposed by Ms. Ramas? (Ramas Direct, lines 272-274.)

A. Allowing recovery of the PTCs through the RTM better matches costs and benefits and ensures customers receive the benefits of the Combined Projects. The current PTCs included in base rates have already begun expiring, and the Company is not proposing to modify base rates to remove expiring PTCs. The Company is proposing to pass through 100 percent of the new PTC benefits through the RTM.

PTC benefits are tied to the output of the wind turbines. As the annual wind output varies, this results in changes to EBA-related NPC but currently the PTCs associated with the wind production are not captured. The energy impact of wind production is captured in the EBA; therefore, the Company is proposing to capture the impact on PTCs in the RTM. This will match the benefits and costs associated with varying wind production. Also, as previously mentioned, customers will receive all of the PTC benefits associated with the Combined Projects.

Project Benefits

Q. Do you agree with the parties' argument that the Combined Projects are discretionary, uneconomical and pose unacceptable risks to customers? (Zenger Direct, lines 248-268; Vastag Direct, lines 53-64; Mullins Direct, page 10, lines 17-20.)

A. No. The proposed resources are a least-cost opportunity to fill both a near-term and long-term resource need, so they should not be dismissed as discretionary. The Company's economic analysis also shows that customer benefits substantially outweigh the costs and that forgoing the time-sensitive opportunity to acquire the Combined Projects will result in higher customer costs in the long-term. In addition, the investment in the Combined Projects does not impose a greater risk on customers than other utility investments.

Moreover, in light of the off-ramps built into the Company's development schedule, approval of the resource decisions in this proceeding does not lock in the decision to proceed if circumstances change before the final notices to proceed, as discussed by Company witness Mr. Chad A. Teply.

Q. Mr. Peaco, Dr. Zenger, and Mr. Mullins also argue that the Company's proposal is inequitable because the Company's shareholders will receive substantially more benefits than customers. (Peaco Direct, lines 227-277; Mullins Direct, page 9, line 1-2; Zenger Direct, lines 102-125.) Do you agree with this characterization?

A. No. The purported shareholder benefit is the capital cost incurred to fund the Combined Projects. A basic premise of ratemaking, however, is that "a capital-attracting rate of profit is here considered a part of the necessary cost of service."[5] The cost of capital is no different than any other prudent cost recoverable in rates if incurred to provide utility service. It is inaccurate to say that shareholders are receiving a greater benefit than customers based on the fact that shareholders recover the costs incurred to provide utility service.

The Company has shown it can deliver additional generation to customers at a lower cost than the alternatives, resulting in a net benefit to customers. The customer benefits assume that shareholders recover the full cost of the Combined Projects

[5] James C. Bonbright, Albert L. Danielsen, & David R. Kamerschen, *Principles of Public Utility Rates*, 112 (2d ed. Public Utilities Reports 1988).

investment, including capital costs.

After the next rate case, the prudent costs and benefits of the Combined Projects will be included in the Company's full revenue requirement. However, there is no guarantee the Company will recover its full cost of service related to the investment. The Company must prudently manage its costs to achieve the full return allowed by the Commission.

Q. Has the Commission previously approved resource acquisitions based on their economic benefits to customers?

A. Yes. The Commission has allowed cost recovery for the Cholla, Craig and Hayden, and Chehalis power plants. All of these were economic opportunities, and in every case, the Commission determined these facilities were in the best interest of customers, *i.e.*, acquiring these resources provided net savings to customers. Although there were customer risks with the resource decision in each case, the Commission allowed full recovery. Consistent with this precedent, if the Commission determines the Combined Projects provide customer benefits, based on what is known today, it should allow full recovery of the costs associated with the Combined Projects.

Q. Has any party to this case previously supported similar economic resource decisions?

A. Yes. When the Company acquired the Chehalis plant in 2008, DPU and UAE both supported the Company's decision to acquire the plant ahead of need. *In the Matter of the Request of Rocky Mountain Power for a Waiver of the Solicitation Process and for Approval of Significant Energy Resource Decision*, Docket No. 08-035-35, Report and Order at 9 (Aug. 1, 2008). In its testimony, DPU noted that the Company's "latest IRP

[had] no expectation that a major thermal generation plant would be acquired between 2007 and 2012" and that the "Chehalis plant would replace a similar natural gas CCCT 500 MW plant that was to be built or acquired in the later time frame." Docket No. 08-035-35, Exhibit No. DPU 1.0, Peterson Direct, page 10, lines 205-208. DPU supported the acquisition ahead of need, in part, because DPU believed it was in the public interest for the Company to "control generation assets rather than to purchase power on the wholesale market." *Id.*, page 11, lines 226-230. DPU testified that there were considerable risks associated with relying on market transactions and that the flexibility provided by owning the plant provided a benefit, even though it could not be directly quantified. *Id.*, page 11, lines 236-238; page 12, lines 255-259.

Q. What conditions does the Company accept related to its request for approval of its resource decisions and RTM?

A. The Company agrees that approval of the Combined Projects and RTM would be conditional on the circumstances known at the time of approval. If there is a change in circumstances that may materially affect the Combined Projects, the Company agrees to return to the Commission for review, as provided in Utah Code Ann. § 54-17-304.

In addition, the law allows the Commission to determine the maximum amount of costs to be included in rates (Utah Code Ann. § 54-17-303), which is effectively a soft cap. The Company agrees that the RTM would be consistent with that soft cap and reflect actual costs (and benefits), up to a maximum of the final estimated costs from this proceeding. The Company would apply for prudence determination of any variances from the estimates in the next rate case, as provided in Utah Code Ann. § 54-17-303(1)(c).

Q. Bela Vastag on behalf of the OCS recommends that in light of "the current level of uncertainty in the Multi State Process" the Commission should approve a maximum cost for Utah using the existing allocations methods, if the Commission approves the Combined Projects. (Vastag Direct, lines 65-73.) Do you think this is a reasonable argument and recommendation?

A. No. The OCS is essentially asking the Commission to pre-judge the outcome of the Multi-State Process ("MSP") discussions that are underway with a presumption that Utah customers will be worse off with any changes in allocation methods. MSP discussions are balancing a number of considerations and complexity among the states but should not be viewed and judged in isolation to any one resource decision. The impacts to Utah from changes to allocation methods for all resources will be considered in discussions among the states in MSP. Pre-determining future ratemaking treatment for one set of resources would be contrary to efforts currently underway. Moreover, the OCS recommendation to set a maximum cost to Utah using the current allocation methods fails to recognize that the current allocation methods use dynamic allocation factors that fluctuate up and down and doesn't address whether benefits would also be capped to Utah. As such, the OCS recommendation is incomplete and inconsistent with the current allocation methods.

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

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JRS-1SD)
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct and Rebuttal Testimony of
Joelle R. Steward

Revenue Requirement Overview

January 2018

Resource Tracking Mechanism

Revenue Requirement Overview – The Combined Projects

<table>
<tr><th>Category</th><th>Base</th><th>New</th><th>Deferral</th></tr>
<tr><td>Capital Investment</td><td>Zero unless the assets or part of the assets have been included in a general rate case. After a rate case, the base will be the amount included in the test period, beginning on the rate effective date of that case.</td><td>Actual monthly beginning plant in-service balances associated with the Combined Projects, beginning with first assets placed in service.</td><td rowspan="7">The difference between the base and new columns will be included in the mechanism calculation until the amounts are fully included in a general rate case, at which time this will end.</td></tr>
<tr><td>Accumulated Depreciation Reserve</td><td>Same as capital investment.</td><td>Monthly depreciation reserve of Combined Projects.</td></tr>
<tr><td>Accumulated Deferred Income Tax</td><td>Same as capital investment.</td><td>Actual accumulated deferred income tax balances associated with the Combined Projects.</td></tr>
<tr><td>Operation & Maintenance Expense</td><td>Zero unless the assets or part of the assets have been included in a general rate case. After a rate case, the base will be the amount included in the test period, beginning on the rate effective date of that case.</td><td>Actual O&M expense for the Combined Projects.</td></tr>
<tr><td>Depreciation Expense</td><td>Zero.</td><td>Actual monthly plant in-service balances associated with the Combined Projects less the base multiplied by current depreciation rates.</td></tr>
<tr><td>Property Taxes</td><td>Zero.</td><td>Capital Investment deferral less the Depreciation Reserve deferral multiplied by the average property tax rate from the last rate case.</td></tr>
<tr><td>Wind Tax</td><td>Zero.</td><td>Incremental energy production MWh associated with Wind Projects subject to the Wyoming Wind tax multiplied by the wind tax rate.</td></tr>
<tr><td>NPC Savings</td><td>The EBA tracks and captures any incremental changes to wind production between NPC in base rates and actual NPC.</td><td>The EBA has a 100% pass through of the difference between base NPC and actual NPC. The RTM will capture any savings, if any, not included in the EBA related to incremental energy production associated with the Wind Projects, and pass these savings back to customers.</td><td>Any incremental wind production associated with the Wind Projects not in base rates will be multiplied by monthly HLH and LLH prices, (Four Corners for east resources) less wind integration costs.</td></tr>
<tr><td>Wheeling Revenues</td><td>Zero unless the Transmission Projects have been included, or partially included, in a general rate case. After a rate case, the base will be the amount included in the test period, beginning on the rate effective date of that case.</td><td>The EBA has a 100% pass through of wheeling revenues. The RTM will capture any incremental Transmission Projects wheeling revenues associated with the Transmission Project not included in the EBA.</td><td>Any incremental third-party wheeling revenues associated with the Transmission Projects, if any, not included in the EBA or in base rates</td></tr>
<tr><td>PTC</td><td>Zero until the next general rate case. After a rate case, the base will be the amount included in the test period, starting on the rate effective date, associated with the Wind Projects.</td><td>Actual MWh eligible for PTC produced by the Wind Projects multiplied by the production tax rate.</td><td>Difference between the base and actual. Tracked until Wind Project PTC's have expired, and have been reset to zero in base rates.</td></tr>
</table>

Rocky Mountain Power
Exhibit RMP___(JRS-2SD)
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct and Rebuttal Testimony
of Joelle R. Steward

Example Annual RTM Deferral Calculation – Revenue Requirement

January 2018

PacifiCorp
Utah
Combined Projects - Example Annual RTM Deferral Calculation
Revenue Requirement

Table 1

The Combined Projects Estimated Revenue Requirement Cost (Benefit)
$thousands

		2020	2021	2022	2023
1	Total Company Revenue Requirement	(4,218)	71,633	58,105	41,953
2	Utah Allocated	(1,798)	30,511	24,745	17,860
3	Utah EBA	(5,628)	(37,460)	(37,524)	(38,249)
4	Utah Deferral	3,830	67,971	62,269	56,110
5	Net Customer Impact	(1,798)	30,511	24,745	17,860

PacifiCorp
Utah
Combined Projects - Example Annual RTM Deferral Calculation
Revenue Requirement

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	$-Thousands		2020 Energy Gateway				2021 Energy Gateway				2022 Energy Gateway				2023 Energy Gateway			
Line No.		Reference	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated
	Plant Revenue Requirement																	
1	Capital Investment	Footnote 1	169,249	SG	42.6283%	72,148	2,071,391	SG	42.6283%	882,999	2,073,460	SG	42.6283%	883,881	2,075,565	SG	42.6283%	884,778
2	Depreciation Reserve	Footnote 1	(475)	SG	42.6283%	(202)	(37,148)	SG	42.6283%	(15,835)	(96,747)	SG	42.6283%	(41,242)	(156,379)	SG	42.6283%	(66,662)
3	Accumulated DIT Balance	Footnote 1	(480)	SG	42.6283%	(205)	(105,277)	SG	42.6283%	(44,878)	(190,515)	SG	42.6283%	(81,213)	(241,046)	SG	42.6283%	(102,754)
4	Net Rate Base	sum of lines 1-3	168,294			71,741	1,928,966			822,286	1,786,197			761,425	1,678,140			715,362
5	Pre-Tax Rate of Return	line 37	9.209%			9.209%	9.209%			9.209%	9.209%			9.209%	9.209%			9.209%
6	Pre-Tax Return on Rate Base	line 4 * line 5	15,499			6,607	177,648			75,728	164,499			70,123	154,548			65,881
7	Wholesale Wheeling Revenue	Footnote 4	(951)	SG	42.6283%	(405)	(10,876)	SG	42.6283%	(4,636)	(10,593)	SG	42.6283%	(4,515)	(10,300)	SG	42.6283%	(4,391)
8	Operation & Maintenance	Footnote 3	4,004	SG	42.6283%	1,707	23,191	SG	42.6283%	9,886	23,348	SG	42.6283%	9,953	23,088	SG	42.6283%	9,842
9	Depreciation	Footnote 3	9,853	SG	42.6283%	4,200	59,574	SG	42.6283%	25,395	59,611	SG	42.6283%	25,411	59,702	SG	42.6283%	25,450
10	Property Taxes	Footnote 3	-	GPS	42.4704%	-	15,829	GPS	42.4704%	6,723	15,406	GPS	42.4704%	6,543	14,949	GPS	42.4704%	6,349
11	Wind Tax	Footnote 3	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	615	SG	42.6283%	262
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**28,405**			**12,109**	**265,365**			**113,096**	**252,271**			**107,514**	**242,602**			**103,393**
	Net Power Cost																	
13	NPC Incremental Savings	Footnote 3	(12,253)	SG	42.6283%	(5,223)	(77,001)	SG	42.6283%	(32,824)	(77,434)	SG	42.6283%	(33,009)	(79,428)	SG	42.6283%	(33,859)
	PTC Benefit																	
14	PTC Benefit	Footnote 3	(15,363)	SG	42.6283%	(6,549)	(88,030)	SG	42.6283%	(37,526)	(88,030)	SG	42.6283%	(37,526)	(91,416)	SG	42.6283%	(38,969)
15	PTC Benefit in Base Rates	Footnote 3	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-
16	Net PTC	sum of lines 14 and 15	(15,363)			(6,549)	(88,030)			(37,526)	(88,030)			(37,526)	(91,416)			(38,969)
17	Gross- up for taxes	line 16 * (line 35 - 1)	(5,009)			(2,135)	(28,701)			(12,235)	(28,701)			(12,235)	(29,805)			(12,705)
18	PTC Revenue Requirement	sum of lines 16 and 17	(20,371)			(8,684)	(116,731)			(49,760)	(116,731)			(49,760)	(121,221)			(51,674)
19	**Rev. Requirement**	sum of lines 12, 13, 18	(4,218)			(1,798)	71,633			30,511	58,105			24,745	41,953			17,860
	Adjustment for EBA Pass-through																	
20	Wholesale Wheeling Revenue	line 7				(405)				(4,636)				(4,515)				(4,391)
21	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%				100%				100%
22	EBA Pass-through	line 20 * line 21				(405)				(4,636)				(4,515)				(4,391)
23	NPC Incremental Savings	line 13				(5,223)				(32,824)				(33,009)				(33,859)
24	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%				100%				100%
25	EBA Pass-through	line 23 * line 24				(5,223)				(32,824)				(33,009)				(33,859)
26	**Rev. Reqt. after EBA Pass-through**	line 19 - line 22 - line 25				3,830				67,971				62,269				56,110
27	**Total Deferral - UT Share**					3,830				67,971				62,269				56,110
28	**Net Customer Benefit**	sum of lines 22, 25, 27				(1,798)				30,511				24,745				17,860
	Deferral Balance - UT Share																	
29	Beginning Deferral Balance	line 33 of previous year				-				3,836				70,840				88,257
30	Monthly Deferral	line 27				3,830				67,971				62,269				56,110
31	Deferral Collection	Footnote 3				-				(2,557)				(48,505)				(82,451)
32	Carrying Charge	Footnote 3				6				1,590				3,653				3,305
33	**Ending Deferral Balance**	sum of lines 29 - 32				3,836				70,840				88,257				65,221

34	Federal/State Combined Tax Rate	JRS-4SD, line 5	24.587%	
35	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6	1.3260	
36	Deferred Balance Carrying Charge	Footnote 2	4.19%	Carrying Charge Order approved in Docket Nos. 17-035-T02 and 15-035-69
37	Pretax Return	JRS-4SD, line 4	9.209%	13-035-184 Capital Structure & Cost - Ordered
38	Property Tax Rate	JRS-4SD, line 14	0.77%	Property Tax Expense as a percent of Net plant from 13-035-184
39	Utah SG Factor	JRS-4SD, line 15	42.6283%	
40	Utah GPS Factor	JRS-4SD, line 16	42.4704%	

Footnotes:
1) Capital balances equal the average of the monthly balances in JRS-3SD with a one month delay
2) Carrying Charge (line 29) is applied to average monthly deferral balances
3) Equals the sum of each year's monthly values in JRS-3SD
4) Includes Wholesale Wheeling Revenue offset for transmission asset credit already in base rates

Rocky Mountain Power
Exhibit RMP___(JRS-3SD)
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct and Rebuttal Testimony
of Joelle R. Steward

Example Monthly RTM Deferral Calculation – Revenue Requirement

January 2018

PacifiCorp
Utah
Combined Projects - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
	Total Company													
	Plant Revenue Requiremen													
1	Capital Investment		-	-	-	-	-	-	-	-	-	282,944	1,748,047	2,068,833
2	Depreciation Reserve		-	-	-	-	-	-	-	-	-	(804)	(4,893)	(9,853)
3	Accumulated DIT Balance		-	-	-	-	-	-	-	-	-	-	(5,761)	(67,591)
4	Net Rate Base	sum of lines 1-3	-	-	-	-	-	-	-	-	-	282,140	1,737,392	1,991,389
5	Pre-Tax Rate of Return	line 37	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	-	-	-	-	-	-	-	-	-	-	2,165	13,334
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	(143)	(808)
8	Operation & Maintenance		-	-	-	-	-	-	-	-	-	-	2,002	2,002
9	Depreciation		-	-	-	-	-	-	-	-	-	804	4,089	4,960
10	Property Taxes	Prior December (line 1 + line 2) x line 37	-	-	-	-	-	-	-	-	-	-	-	-
11	Wind Tax		-	-	-	-	-	-	-	-	-	-	-	-
12	**Total Plant Revenue Requiremen**	sum of lines 6-11	-	-	-	-	-	-	-	-	-	804	8,113	19,488
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	-	-	-	-	-	-	-	-	-	-	(6,126)	(6,126)
	PTC Benefit													
14	PTC Benefit		-	-	-	-	-	-	-	-	-	-	(7,681)	(7,681)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	-	-	-	-	-	-	-	-	-	-	(7,681)	(7,681)
17	Gross- up for taxes	line 16 * (line 35 - 1)	-	-	-	-	-	-	-	-	-	-	(2,504)	(2,504)
18	PTC Revenue Requirement	sum of line 16 and 17	-	-	-	-	-	-	-	-	-	-	(10,186)	(10,186)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	-	-	-	-	-	-	-	-	-	804	(8,198)	3,176
	Adjustment for EBA Pass-througl													
20	Wholesale Wheeling Revenue	line 7	-	-	-	-	-	-	-	-	-	-	(143)	(808)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	-	-	-	-	-	-	-	-	-	-	(143)	(808)
23	NPC Incremental Savings	line 13	-	-	-	-	-	-	-	-	-	-	(6,126)	(6,126)
24	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
25	EBA Pass-through	line 23 * line 24	-	-	-	-	-	-	-	-	-	-	(6,126)	(6,126)
26	**Rev. Reqt after EBA Pass-througl**	line 19 - line 22 - line 25	-	-	-	-	-	-	-	-	-	804	(1,929)	10,110
	Utah Allocated													
27	**Total Deferral - UT Share**	(Ln 26 - ln 10) * ln 39 + ln 10 * ln 40	-	-	-	-	-	-	-	-	-	343	(822)	4,310
28	**Net Customer Benefit**	(line 22 + line 25) * line 36 + line 24	-	-	-	-	-	-	-	-	-	343	(3,495)	1,354
	Deferral Balance - UT Share													
29	Beginning Deferral Balance	line 33 of previous month	-	-	-	-	-	-	-	-	-	-	343	(479)
30	Monthly Deferral	line 24	-	-	-	-	-	-	-	-	-	343	(822)	4,310
31	Deferral Collection	Footnote 3	-	-	-	-	-	-	-	-	-	-	-	-
32	Carrying Charge	(ln 29+ .5 * (ln 30 + ln 31)) * ln 36	-	-	-	-	-	-	-	-	-	1	(0)	6
33	**Ending Deferral Balance**	sum of lines 29-32	-	-	-	-	-	-	-	-	-	343	(479)	3,836
34	Federal/State Combined Tax Rate	JRS-4SD, line 5	24.587%											
35	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6	1.3260											
36	Deferred Balance Carrying Charge	see JRS-2S Page 2 line 36	4.19%											
37	Pretax Return	JRS-4SD, line 4	9.209%											
38	Property Tax Rate	JRS-4SD, line 14	0.77%											
39	Utah SG Factor	JRS-4SD, line 15	42.6283%											
40	Utah GPS Factor	JRS-4SD, line 16	42.4704%											

Footnotes:

1) Pre-tax Return, line 6, is calculated as the rate of return (line 5) multiplied by the ending net rate base of the prior month (line 4) divided by 12

2) Includes Wholesale Wheeling Revenue offset for transmission asset credit already in base rates

3) For illustrative purposes, collection of December's balance is assumed to be collected beginning the following May 1

PacifiCorp
Utah
Combined Projects - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December
	Total Company													
	Plant Revenue Requiremen													
1	Capital Investment		2,068,833	2,068,833	2,068,833	2,068,833	2,073,043	2,073,043	2,073,269	2,073,269	2,073,269	2,073,269	2,073,363	2,073,363
2	Depreciation Reserve		(14,813)	(19,773)	(24,732)	(29,692)	(34,658)	(39,625)	(44,592)	(49,559)	(54,526)	(59,492)	(64,460)	(69,427)
3	Accumulated DIT Balance		(67,591)	(67,591)	(92,715)	(92,715)	(92,715)	(117,839)	(117,839)	(117,839)	(142,962)	(142,962)	(142,962)	(168,086)
4	Net Rate Base	sum of lines 1-3	1,986,429	1,981,469	1,951,386	1,946,426	1,945,670	1,915,580	1,910,839	1,905,872	1,875,781	1,870,814	1,865,941	1,835,850
5	Pre-Tax Rate of Return	line 37	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	15,283	15,245	15,207	14,976	14,938	14,932	14,701	14,665	14,627	14,396	14,358	14,320
7	Wholesale Wheeling Revenue	Footnote 2	(914)	(913)	(912)	(908)	(908)	(910)	(906)	(905)	(904)	(900)	(899)	(898)
8	Operation & Maintenance		1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933
9	Depreciation		4,960	4,960	4,960	4,960	4,966	4,966	4,967	4,967	4,967	4,967	4,967	4,967
10	Property Taxes	Prior December (line 1 + line 2) x line 37	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
11	Wind Tax		-	-	-	-	-	-	-	-	-	-	-	-
12	**Total Plant Revenue Requiremen**	sum of lines 6-11	22,580	22,543	22,506	22,280	22,248	22,240	22,014	21,978	21,941	21,715	21,678	21,642
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)
	PTC Benefit													
14	PTC Benefit		(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)
17	Gross- up for taxes	line 16 * (line 35 - 1)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)
18	PTC Revenue Requirement	sum of line 16 and 17	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	6,436	6,399	6,362	6,135	6,104	6,095	5,869	5,834	5,797	5,570	5,534	5,497
	Adjustment for EBA Pass-througl													
20	Wholesale Wheeling Revenue	line 7	(914)	(913)	(912)	(908)	(908)	(910)	(906)	(905)	(904)	(900)	(899)	(898)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(914)	(913)	(912)	(908)	(908)	(910)	(906)	(905)	(904)	(900)	(899)	(898)
23	NPC Incremental Savings	line 13	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)
24	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
25	EBA Pass-through	line 23 * line 24	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)
26	**Rev. Reqt after EBA Pass-througl**	line 19 - line 22 - line 25	13,767	13,729	13,691	13,460	13,428	13,423	13,192	13,156	13,118	12,887	12,849	12,812
	Utah Allocated													
27	**Total Deferral - UT Share**	(Ln 26 - ln 10) * ln 39 + ln 10 * ln 40	5,866	5,850	5,834	5,736	5,722	5,720	5,622	5,606	5,590	5,491	5,475	5,459
28	**Net Customer Benefit**	(line 22 + line 25) * line 36 + line 24	2,741	2,726	2,710	2,613	2,600	2,596	2,500	2,485	2,469	2,372	2,357	2,341
	Deferral Balance - UT Share													
29	Beginning Deferral Balance	line 33 of previous month	3,836	9,726	15,621	21,520	27,340	32,848	38,372	43,817	49,265	54,717	60,089	65,463
30	Monthly Deferral	line 24	5,866	5,850	5,834	5,736	5,722	5,720	5,622	5,606	5,590	5,491	5,475	5,459
31	Deferral Collection	Footnote 3	-	-	-	-	(320)	(320)	(320)	(320)	(320)	(320)	(320)	(320)
32	Carrying Charge	(ln 29+ .5 * (ln 30 + ln 31)) * ln 36	24	44	65	85	105	124	143	162	181	200	219	238
33	**Ending Deferral Balance**	sum of lines 29-32	9,726	15,621	21,520	27,340	32,848	38,372	43,817	49,265	54,717	60,089	65,463	70,840
34	Federal/State Combined Tax Rate	JRS-4SD, line 5												
35	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6												
36	Deferred Balance Carrying Charge	see JRS-2S Page 2 line 36												
37	Pretax Return	JRS-4SD, line 4												
38	Property Tax Rate	JRS-4SD, line 14												
39	Utah SG Factor	JRS-4SD, line 15												
40	Utah GPS Factor	JRS-4SD, line 16												

Footnotes:

1) Pre-tax Return, line 6, is calculated as the rate of return (line 5) multiplied by the ending net rate base of the prior month (line 4) divided by 12

2) Includes Wholesale Wheeling Revenue offset for transmission asset credit already in base rates

3) For illustrative purposes, collection of December's balance is assumed to be collected beginning the following May 1

PacifiCorp
Utah
Combined Projects - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December
	Total Company													
	Plant Revenue Requiremen													
1	Capital Investment		2,073,363	2,073,363	2,073,363	2,073,363	2,073,363	2,073,363	2,073,595	2,073,595	2,073,595	2,073,595	2,073,595	2,073,595
2	Depreciation Reserve		(74,394)	(79,361)	(84,329)	(89,296)	(94,263)	(99,230)	(104,198)	(109,166)	(114,134)	(119,102)	(124,070)	(129,038)
3	Accumulated DIT Balance		(168,086)	(168,086)	(183,039)	(183,039)	(183,039)	(197,991)	(197,991)	(197,991)	(212,944)	(212,944)	(212,944)	(227,896)
4	Net Rate Base	sum of lines 1-3	1,830,883	1,825,915	1,805,996	1,801,028	1,796,061	1,776,141	1,771,405	1,766,438	1,746,517	1,741,549	1,736,581	1,716,661
5	Pre-Tax Rate of Return	line 37	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	14,089	14,051	14,013	13,860	13,822	13,784	13,631	13,595	13,557	13,404	13,366	13,327
7	Wholesale Wheeling Revenue	Footnote 2	(893)	(892)	(891)	(887)	(886)	(885)	(881)	(880)	(879)	(875)	(874)	(873)
8	Operation & Maintenance		1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946
9	Depreciation		4,967	4,967	4,967	4,967	4,967	4,967	4,968	4,968	4,968	4,968	4,968	4,968
10	Property Taxes	Prior December (line 1 + line 2) x line 37	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284
11	Wind Tax		-	-	-	-	-	-	-	-	-	-	-	-
12	**Total Plant Revenue Requiremen**	sum of lines 6-11	21,393	21,356	21,319	21,170	21,133	21,096	20,948	20,912	20,875	20,726	20,689	20,652
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)
	PTC Benefit													
14	PTC Benefit		(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)	(7,336)
17	Gross- up for taxes	line 16 * (line 35 - 1)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)	(2,392)
18	PTC Revenue Requirement	sum of line 16 and 17	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)	(9,728)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	5,213	5,176	5,139	4,990	4,953	4,916	4,767	4,732	4,695	4,546	4,509	4,472
	Adjustment for EBA Pass-througl													
20	Wholesale Wheeling Revenue	line 7	(893)	(892)	(891)	(887)	(886)	(885)	(881)	(880)	(879)	(875)	(874)	(873)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(893)	(892)	(891)	(887)	(886)	(885)	(881)	(880)	(879)	(875)	(874)	(873)
23	NPC Incremental Savings	line 13	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)
24	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
25	EBA Pass-through	line 23 * line 24	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)	(6,453)
26	**Rev. Reqt after EBA Pass-througl**	line 19 - line 22 - line 25	12,558	12,520	12,482	12,329	12,291	12,253	12,101	12,065	12,026	11,874	11,835	11,797
	Utah Allocated													
27	**Total Deferral - UT Share**	(Ln 26 - ln 10) * ln 39 + ln 10 * ln 40	5,351	5,335	5,319	5,254	5,237	5,221	5,156	5,141	5,125	5,059	5,043	5,027
28	**Net Customer Benefit**	(line 22 + line 25) * line 36 + line 24	2,220	2,204	2,189	2,125	2,109	2,093	2,030	2,015	1,999	1,936	1,920	1,904
	Deferral Balance - UT Share													
29	Beginning Deferral Balance	line 33 of previous month	70,840	76,128	81,418	86,710	91,956	91,610	91,246	90,817	90,370	89,905	89,374	88,824
30	Monthly Deferral	line 24	5,351	5,335	5,319	5,254	5,237	5,221	5,156	5,141	5,125	5,059	5,043	5,027
31	Deferral Collection	Footnote 3	(320)	(320)	(320)	(320)	(5,903)	(5,903)	(5,903)	(5,903)	(5,903)	(5,903)	(5,903)	(5,903)
32	Carrying Charge	(ln 29+ .5 * (ln 30 + ln 31)) * ln 36	256	275	293	311	320	319	317	316	314	312	311	309
33	**Ending Deferral Balance**	sum of lines 29-32	76,128	81,418	86,710	91,956	91,610	91,246	90,817	90,370	89,905	89,374	88,824	88,257
34	Federal/State Combined Tax Rate	JRS-4SD, line 5												
35	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6												
36	Deferred Balance Carrying Charge	see JRS-2S Page 2 line 36												
37	Pretax Return	JRS-4SD, line 4												
38	Property Tax Rate	JRS-4SD, line 14												
39	Utah SG Factor	JRS-4SD, line 15												
40	Utah GPS Factor	JRS-4SD, line 16												

Footnotes:

1) Pre-tax Return, line 6, is calculated as the rate of return (line 5) multiplied by the ending net rate base of the prior month (line 4) divided by 12

2) Includes Wholesale Wheeling Revenue offset for transmission asset credit already in base rates

3) For illustrative purposes, collection of December's balance is assumed to be collected beginning the following May 1

PacifiCorp
Utah
Combined Projects - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December
	Total Company													
	Plant Revenue Requiremen													
1	Capital Investment		2,073,595	2,073,595	2,073,595	2,073,595	2,073,595	2,073,595	2,078,323	2,078,323	2,078,323	2,078,323	2,078,323	2,078,323
2	Depreciation Reserve		(134,006)	(138,973)	(143,941)	(148,909)	(153,877)	(158,845)	(163,828)	(168,810)	(173,793)	(178,775)	(183,758)	(188,740)
3	Accumulated DIT Balance		(227,896)	(227,896)	(236,663)	(236,663)	(236,663)	(245,429)	(245,429)	(245,429)	(254,195)	(254,195)	(254,195)	(262,962)
4	Net Rate Base	sum of lines 1-3	1,711,693	1,706,725	1,692,991	1,688,023	1,683,055	1,669,321	1,669,067	1,664,084	1,650,335	1,645,353	1,640,370	1,626,622
5	Pre-Tax Rate of Return	line 37	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	13,175	13,136	13,098	12,993	12,955	12,917	12,811	12,809	12,771	12,666	12,627	12,589
7	Wholesale Wheeling Revenue	Footnote 2	(868)	(867)	(866)	(862)	(861)	(860)	(857)	(855)	(854)	(851)	(850)	(849)
8	Operation & Maintenance		1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924	1,924
9	Depreciation		4,968	4,968	4,968	4,968	4,968	4,968	4,982	4,982	4,982	4,982	4,982	4,982
10	Property Taxes	Prior December (line 1 + line 2) x line 37	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246
11	Wind Tax		51	51	51	51	51	51	51	51	51	51	51	51
12	**Total Plant Revenue Requiremen**	sum of lines 6-11	20,496	20,459	20,422	20,320	20,283	20,246	20,158	20,157	20,120	20,018	19,981	19,944
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)
	PTC Benefit													
14	PTC Benefit		(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)	(7,618)
17	Gross- up for taxes	line 16 * (line 35 - 1)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)	(2,484)
18	PTC Revenue Requirement	sum of line 16 and 17	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)	(10,102)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	3,775	3,738	3,701	3,599	3,562	3,525	3,437	3,437	3,399	3,297	3,260	3,223
	Adjustment for EBA Pass-througl													
20	Wholesale Wheeling Revenue	line 7	(868)	(867)	(866)	(862)	(861)	(860)	(857)	(855)	(854)	(851)	(850)	(849)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(868)	(867)	(866)	(862)	(861)	(860)	(857)	(855)	(854)	(851)	(850)	(849)
23	NPC Incremental Savings	line 13	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)
24	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
25	EBA Pass-through	line 23 * line 24	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)	(6,619)
26	**Rev. Reqt after EBA Pass-througl**	line 19 - line 22 - line 25	11,262	11,224	11,185	11,080	11,042	11,004	10,913	10,911	10,873	10,767	10,729	10,691
	Utah Allocated													
27	**Total Deferral - UT Share**	(Ln 26 - ln 10) * ln 39 + ln 10 * ln 40	4,799	4,782	4,766	4,721	4,705	4,689	4,650	4,649	4,633	4,588	4,572	4,555
28	**Net Customer Benefit**	(line 22 + line 25) * line 36 + line 24	1,607	1,591	1,576	1,532	1,516	1,501	1,463	1,463	1,447	1,404	1,388	1,372
	Deferral Balance - UT Share													
29	Beginning Deferral Balance	line 33 of previous month	88,257	87,458	86,641	85,804	84,920	82,562	80,180	77,750	75,311	72,848	70,331	67,788
30	Monthly Deferral	line 24	4,799	4,782	4,766	4,721	4,705	4,689	4,650	4,649	4,633	4,588	4,572	4,555
31	Deferral Collection	Footnote 3	(5,903)	(5,903)	(5,903)	(5,903)	(7,355)	(7,355)	(7,355)	(7,355)	(7,355)	(7,355)	(7,355)	(7,355)
32	Carrying Charge	(ln 29+ .5 * (ln 30 + ln 31)) * ln 36	306	303	301	298	292	284	275	267	258	250	241	232
33	**Ending Deferral Balance**	sum of lines 29-32	87,458	86,641	85,804	84,920	82,562	80,180	77,750	75,311	72,848	70,331	67,788	65,221
34	Federal/State Combined Tax Rate	JRS-4SD, line 5												
35	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6												
36	Deferred Balance Carrying Charge	see JRS-2S Page 2 line 36												
37	Pretax Return	JRS-4SD, line 4												
38	Property Tax Rate	JRS-4SD, line 14												
39	Utah SG Factor	JRS-4SD, line 15												
40	Utah GPS Factor	JRS-4SD, line 16												

Footnotes:

1) Pre-tax Return, line 6, is calculated as the rate of return (line 5) multiplied by the ending net rate base of the prior month (line 4) divided by 12

2) Includes Wholesale Wheeling Revenue offset for transmission asset credit already in base rates

3) For illustrative purposes, collection of December's balance is assumed to be collected beginning the following May 1

PacifiCorp
Utah
Combined Projects - Example Monthly RTM Deferral Calculation
Revenue Requirement

Total Plant Revenue Requirement (Lines 1 - 12, 37):
Exhibit JRS-3SD shows the calculation of the RTM revenue requirement deferral described in my testimony. The calculation starts with total Company amounts on lines 1 - 26 to calculate the Utah specific amounts on lines 27 - 33. To calculate the return on rate base associated with the combined investment, net rate base is calculated on a monthly basis. The net rate base balance on line 4 includes the combined investment in wind and transmission resources, along with the associated impacts on the depreciation reserve and accumulated DIT Balance. The monthly beginning net rate base (the final amount from the prior month) is then multiplied by the pre-tax Weighted Average Cost of Capital ("WACC") from the last Utah general rate case, updated for the new tax law, on line 5 to determine the Company's pre-tax return on rate base on line 6. The example uses the pre-tax WACC from Docket No. 13-035-15. The total plant revenue requirement is calculated by taking the return on rate base shown on line 6 and adding wholesale wheeling revenue, O&M expense, depreciation expense, property taxes and wind tax on lines 7 - 11 to determine the total plant revenue requirement on line 12. Wholesale wheeling revenue on line 7 reflects the 3rd party wheeling revenue associated with the new transmission investment and is multiplied by one hundred percent on line 21 to determine the amount of wheeling revenue that will be returned to customers through the sharing band of the EBA.

Net Power Costs (Line 13):
The total company incremental NPC savings associated with new wind resources is shown on line 13. The incremental NPC savings associated with the new wind projects are multiplied by one hundred percent on line 24 to determine the amount of the NPC savings that will be returned to customers through the sharing band of the EBA.

PTC Benefits (Lines 14-18, 34, 35):
Lines 14-18 show the calculation of the PTC benefits associated with the new wind resources. The actual PTC sales are grossed-up for taxes using the net-to-gross bump-up factor from the Company's last general rate case (shown on line 35 - updated for the new tax law) to derive the PTC revenue requirement on line 18. The tax gross-up is necessary for customers to get the full revenue requirement benefit of the PTCs and is calculated using the federal and state combined tax rate shown on line 34, which was also included in the last general rate case.

Deferral Balance (Lines 19 – 30):
The Utah share of the net deferral begins by calculating the total combined project revenue requirement on line 19, which is the sum of Total Plant Revenue Requirement on line 12, NPC Incremental Savings on line 13, and PTC Revenue Requirement on line 18. The Wholesale Wheeling Revenue pass-through on line 22 and the NPC EBA pass-through on line 25 are subtracted to provide the Revenue Requirement after EBA Pass-through on line 26. The Net Customer Benefit (line 28) is the sum of the EBA Pass-throughs (line 22 and line 25) and the Total Deferral - Utah Share (line 27). The carrying charge, shown on line 32 is calculated using the Commission-authorized rate on line 36 from the Carrying Charge Order approved in Docket Nos. 17-035-T02 and 15-035-69. As described earlier, each month the total-Company RTM revenue requirement will be calculated as illustrated on Exhibit JRS-3SD to align with the resources included in the EBA. Once per year on a calendar-year basis, the Company will sum the monthly RTM revenue requirement entries to prepare the annual RTM application for filing with the Commission on March 15, with an interim rate effective date that corresponds with the EBA application, May 1.

Rocky Mountain Power
Exhibit RMP___(JRS-4SD)
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct and Rebuttal Testimony
of Joelle R. Steward

Capital Structure, Property Tax Rate, and Net Power Cost Description

January 2018

PacifiCorp
Utah
Combined Projects - Capital Structure, Income Tax Rate, Property Tax Rate
Allocation Factors and Net Power Cost Description

13-035-184 Capital Structure & Cost
Updated with new consolidated tax rate consistent with the new tax law
Effective 9/1/2014

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Pre-Tax Cost
1	Debt	48.556%	5.200%	2.525%	2.525%
2	Preferred	0.016%	6.753%	0.001%	0.001%
3	Common	51.428%	9.800%	5.040%	6.683%
4			**TOTAL**	**7.566%**	**9.209%**
5	Consolidated Tax Rate		24.587%		
6	Tax Gross-up factor for PTC = (1/(1 - tax rate))		1.3260		
	Property Tax Calculation as filed in Docket Number 13-035-184				
7	Total Company				134,961,526
8	Utah GPS Factor				42.4704%
9	Utah Property Taxes				57,318,700
10	Utah Gross EPIS				10,912,081,614
11	Utah Accum. Depr.				(3,234,910,020)
12	Utah Accum. Amort.				(221,249,967)
13	Utah Net EPIS				7,455,921,626
14	Estimated Utah Property Tax Rate				0.769%
15	Utah SG Factor - Docket No. 13-035-184				42.6283%
16	Utah GPS Factor - Docket No. 13-035-184				42.4704%

Net Power Cost Incremental Savings Calculation and Definitions

$$Incremental\ Generation = Wind\ Plant\ Generation\ MWh - Base\ Wind\ Plant\ Generation\ MWh$$

$$NPC\ Incremental\ Savings = [Incremental\ Gen_{HLH} \times (Monthly\ Market\ Price_{HLH} - Integration\ Costs)] + [Incremental\ Gen_{LLH} \times (Monthly\ Market\ Price_{LLH} - Integration\ Costs)]$$

$$RTM\ NPC\ Benefit = NPC\ Incremental\ Savings \times EBA\ Sharing\ Band, if\ applicable$$

Where:

Incremental Generation = The increase in generation at the wind plants due to the Wind Projects
Wind Plant Generation MWh = The wind plant generation associated with the Wind Projects
Base Wind Plant Generation MWh = The wind plant generation associated with the Wind Projects that is included in base rates.
$Incremental\ Gen_{HLH}$ = *The increase in generation at the wind plant due to the Wind Projects during heavy load hours*
$Incremental\ Gen_{LLH}$ = *The increase in generation at the wind plant due to Wind Projects during light load hours*
$Monthly\ Market\ Price_{HLH}$ = *Heavy load hour monthly market price*
$Monthly\ Market\ Price_{LLH}$ = *Light load hour monthly market price*
Integration Costs = Wind integration costs from the most recent IRP
RTM NPC Benefit = The NPC benefit absorbed by the Company in the EBA as a result of the sharing band, if applicable

Rocky Mountain Power
Docket No. 17-035-40
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct and Rebuttal Testimony of Nikki L. Kobliha

January 2018

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

A. My name is Nikki L. Kobliha and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Vice President, Chief Financial Officer and Treasurer for PacifiCorp. I am testifying on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Business Administration with a concentration in Accounting from the University of Portland in 1994. I became a certified public accountant in 1996. I joined the Company in 1997 and have taken on roles of increasing responsibility before being appointed Chief Financial Officer in 2015.

Q. What are your responsibilities as Vice President, Chief Financial Officer and Treasurer?

A. I am responsible for all aspects of the Company's finance, accounting, income tax, internal audit, Securities and Exchange Commission reporting, treasury, credit risk management, pension, and other investment management activities.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. In my testimony, I support the Company's request that the Public Service Commission of Utah ("Commission") approve its significant energy resource decision for new wind resources ("Wind Projects") and voluntary energy resource decision for construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the “Combined Projects”). In my supplemental direct testimony, I outline relevant provisions in the federal income tax reform enacted in December 2017. I confirm that there are no changes to current federal income tax law on production tax credits (“PTCs”), which provide significant value to the Combined Projects.

In my rebuttal testimony, I respond to income tax issues raised in the direct testimonies of Division of Public Utilities (“DPU”) witnesses Dr. Joni Zenger and Mr. Daniel Peaco; Office of Consumer Services (“OCS”) witnesses Mr. Philip Hayet and Ms. Donna Ramas; Utah Association of Energy Users (“UAE”) and Utah Industrial Energy Consumers (“UIEC”) witness Mr. Brad Mullins; and Interwest Energy Alliance (“Interwest”) witness Mr. Gregory F. Jenner.

Q. Please summarize your testimony.

A. In December 2017, the U.S. Congress passed, and the President signed, H.R 1 (“Tax Act”), which included significant federal income tax reforms. The passage of the Tax Act resolved any risk that federal tax reform posed to the Combined Projects. The Tax Act sets a new corporate income tax rate, now incorporated in the Company’s updated economic analysis presented by Company witness Mr. Rick T. Link. It also confirms the continued availability of PTCs for the Combined Projects, from which much of their economic benefit is derived. The enactment of the Tax Act therefore resolves the intervenors’ concerns on this issue since the impacts are now known and incorporated in the economic analysis.

SUPPLEMENTAL DIRECT TESTIMONY

Q. When was the Tax Act enacted?

A. The Tax Act was signed into law by the President on December 22, 2017.

Q. When does the Tax Act become effective?

A. The Tax Act generally becomes effective for years beginning after December 31, 2017.

Q. Does the Tax Act reduce the Company's federal income tax rate?

A. Yes, the Tax Act reduces the Company's federal income tax rate from 35 percent to 21 percent.

Q. Is there a difference between the Company's federal statutory income tax rate and effective tax rate under the Tax Act?

A. No.

Q. Does the reduction in the corporate tax rate directly affect the value of PTCs?

A. No, the reduction in the corporate income tax rate does not directly impact the value of the PTCs. It does, however, impact the tax gross-up value of the PTCs to customers.

Q. Does the Tax Act change any aspect of federal income tax law related to PTCs?

A. No. There were no modifications to the federal income tax code or any Internal Revenue Service ("IRS") guidance relating to the PTCs.

Q. Please describe how a PTC is generated.

A. The Internal Revenue Code ("IRC") provides that a wind facility will generate a PTC equal to an inflation-adjusted 1.5 cents per kilowatt hour of electricity that is produced and sold to a third-party for a period of 10 years beginning on the date the facility is placed in service for income tax purposes.[1] The current inflation-adjusted PTC rate for electricity generated in 2017 is 2.4 cents per kilowatt hour.[2]

[1] IRC section 45(a).

[2] IRS Notice 2017-33.

Q. Under current income tax law, the PTC is being phased out. Please explain the phase-out process.

A. The Protecting Americans from Tax Hikes Act of 2015 ("PATH Act") was signed into law on December 18, 2015, and retroactively extended and phased out the PTC for wind facilities that began construction before January 1, 2020. For a wind facility that began construction before January 1, 2017, the credit generated by the wind facility is a full 100 percent of the PTC. For a wind facility that begins construction in 2017, the credit is reduced by 20 percent (*i.e.*, the facility receives 80 percent of the full PTC). For a wind facility that begins construction in 2018, the credit is reduced by 40 percent (*i.e.*, the facility receives 60 percent of the full PTC). For a wind facility that begins construction in 2019, the credit is reduced by 60 percent (*i.e.*, the facility receives 40 percent of the full PTC).[3] No PTC is available for a wind facility that begin construction after December 31, 2019.

Q. When does "construction" begin for a wind facility?

A. IRS Notice 2013-29 provides a taxpayer with two methods to establish that construction of a wind facility has begun. First, the taxpayer can begin physical work of a significant nature. Physical work can include both on-site and off-site work, either performed by the taxpayer or by another person subject to a binding contract.

Second, a taxpayer can pay or incur five percent or more of the eventual total cost of the qualified wind facility.[4] This is known as the five-percent safe harbor. The Company is using the five-percent safe-harbor method to qualify for 100 percent of the PTC for the benchmark resources selected in the final shortlist. In addition to the

[3] IRC section 42(b)(5).

[4] IRS Notice 2013-29 Section 5.01.

requirement that the wind facility begin construction before January 1, 2017, to qualify for 100 percent of the PTC, the wind facility must also satisfy the continuity-of-construction requirement

Q. Please explain the continuity-of-construction requirement.

A. The wind facility must be under continuous construction from the time physical construction begins until the wind facility is placed in service.[5] Whether a taxpayer satisfies the continuity-of-construction requirement is determined based on the relevant facts and circumstances surrounding the timing of the physical work to be performed on the wind facility.[6] The IRS has issued limited guidance on what facts and circumstances might be considered to meet this requirement. For example, the IRS has provided a list of non-exclusive "excusable" disruptions and delays deemed to be beyond the control of the taxpayer and therefore acceptable reasons that would support the taxpayer's contention that it has maintained a continuous program of construction. These acceptable delays include weather-caused delays, permit delays outside of the control of the taxpayer, and supply shortages, among others.[7]

The IRS has, however, also created a continuity-of-construction safe harbor (the "calendar safe harbor").[8] If a taxpayer places a facility in service by end of a calendar year that is not more than four calendar years after the calendar year during which construction of the wind facility began, the facility will satisfy the continuity-of-construction requirement by virtue of the calendar safe harbor.[9] Accordingly, if

[5] IRS Notice 2016-31 Section 4.
[6] IRS Notice 2016-31 Section 4.02(1).
[7] IRS Notice 2016-31 Section 4.06(2).
[8] IRS Notice 2016-31; IRS Notice 2017-4.
[9] IRS Notice 2016-31 Section 3.

construction of a wind facility began in December 2016, the facility will meet the continuity-of-construction requirement as long as the facility is placed in service by December 31, 2020.

The Company plans to have the Wind Projects placed in service by December 31, 2020, and therefore, the Company will qualify for 100 percent of the PTCs under the four-year calendar safe harbor.

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

A. Yes. As discussed by Company witness Mr. Rick A. Vail in his supplemental direct and rebuttal testimony, the Wind Projects would still qualify if the Transmission Projects have facilitated synchronization to the transmission grid and commissioning of individual wind turbines in accordance with IRS guidance. In Private Letter Ruling ("PLR") 20033403, the IRS ruled that a wind turbine has been placed in service for the purposes of PTC qualification if: (1) the turbine has all necessary operating permits and licenses; (2) the turbine has been synchronized to the power grid; (3) the critical tests for the components of the wind turbine have been completed; (4) the wind turbine has been placed in the control of the taxpayer by the contractor; (5) the taxpayer has sold electricity that has been produced by the wind turbine; and (6) the wind turbine is putting power onto the grid on a regular basis. This IRS guidance applies even if the wind project is not producing transmission-level electricity due to a delay in a transmission project and has not been deemed to be under commercial operation by a regulatory commission. A PLR may not be relied on as precedent by other taxpayers; however, it is indicative of the IRS position on certain matters.

Q. Are there any other provisions of the Tax Act that affect the Combined Projects?

A. Yes. There are two other impacts associated with the reduction in the corporate income tax rate. A reduction to the corporate income tax rate reduces the tax gross-up, lowering the Company's overall rate of return on the Combined Projects. The lower tax rate also reduces the accumulated deferred income tax liability related to the use of Modified Accelerated Cost Recovery System ("MACRS") accelerated depreciation for the five-year tax life of the Wind Projects, which will increase the net rate-base balance.

Bonus depreciation rules have also changed. Under prior income tax law, wind projects placed in service in 2019 by the Company would have received 30-percent bonus depreciation. Wind projects placed in service in 2020 would have received no bonus depreciation. The new tax reform legislation generally provides that regulated utilities such as the Company will not be allowed to use bonus depreciation on projects placed in service after September 27, 2017. The Wind Projects, however, remain subject to the five-year MACRS accelerated depreciation. The impacts of the reduction in the corporate income tax rate and the elimination of bonus deprecation for regulated utilities has been fully reflected in the updated economic analysis prepared by Mr. Link.

Q. Does the reduction in the Company's federal income tax rate make the Combined Projects uneconomic?

A. No, as demonstrated in Mr. Link's updated economic analysis of the Combined Projects.

Q. At this point, do you foresee any future tax reform legislation that will materially impact the economics of the Combined Projects?

A. No.

REBUTTAL TESTIMONY

Q. Mr. Jenner testifies that existing federal tax policies for renewable energy investments are favorable. (Jenner Direct, page 3, lines 9–14.) Do you agree?

A. Yes. Specifically, I agree with Mr. Jenner's observation that PTCs have reached their highest value ever. I also agree that, because of the scheduled phase-out of PTCs, the Company and other large utilities are accelerating their investments in wind projects to capture PTC benefits for their customers before PTCs are zeroed out for projects that begin construction in 2020.

Q. Please summarize the specific concerns raised by intervening parties related to income tax reform.

A. The parties testified that federal income tax reform creates uncertainty that increases customer risk associated with the Combined Projects. These concerns generally focus on the following five issues:

1. A corporate income tax rate reduction from the current 35 percent to around 20 percent.
2. A reduction in PTCs to remove statutory escalation in the rate, reducing PTCs from the escalated 2.4¢/kWh to 1.5¢/kWh.
3. Modifications to IRS guidance regarding compliance with the continuity-of- construction requirement, which could eliminate PTCs for the Wind Projects.
4. Changes to rules governing bonus depreciation that could cause the Combined Projects to no longer qualify for bonus tax depreciation.
5. A provision that would replace the Alternative Minimum Tax called the

Base Erosion Anti-Abuse Tax (“BEAT”), which could result in PTCs only being eligible to offset 90 percent of taxable income in any given year.

As I describe below, the enactment of the Tax Act resolved every one of these issues and these risks are no longer a concern.

Q. Parties contend that the uncertainty surrounding the federal corporate tax rate creates significant risk of decreased customer benefits from the Combined Projects. (Peaco Direct, lines 910–912; Zenger Direct, lines 272–280; Hayet Direct, lines 303–312; Ramas Direct, lines 333–347; Mullins Direct, page 38, line 22–page 39, line 7.) Is there still uncertainty related to the federal corporate tax rate?

A. No. As discussed above, the federal corporate tax rate has decreased to 21 percent beginning in 2018, and there is no reason to believe that another decrease will occur in the near future. As described by Mr. Link, the Combined Projects continue to provide substantial customer benefits under the Company’s new 21 percent federal tax rate.

Q. Parties argued that there is a risk that PTCs could be reduced if tax reform eliminates the statutory escalation rate, consistent with tax reform legislation passed by the House of Representatives. (Peaco Direct, lines 889-892; Zenger Direct, lines 280-282; Hayet Direct, lines 327-332; Ramas Direct, lines 407-412; Mullins Direct, page 39, lines 11-15.) Did the final legislation affect the PTC escalation rate?

A. No.

Q. Parties argue that there is a risk that tax reform legislation could include modifications to the IRS guidance regarding compliance with the continuity-of-construction" requirement. (Peaco Direct, lines 889–902; Ramas Direct, lines 412–415.) Did the final legislation affect this requirement for PTC eligibility?

A. No.

Q. Ms. Ramas testifies that changes to the current bonus depreciation rules could result in the Combined Projects being disqualified for bonus depreciation. (Ramas Direct, lines 442–464.) Did the final legislation affect the Combined Projects' eligibility for bonus depreciation?

A. Yes. But, as I describe above, the change in the treatment of bonus depreciation has been accounted for in the Company's economic analysis and it does not materially impact the economic benefits of the Combined Projects.

Q. Mr. Mullins testifies that the BEAT provision included in the Senate version of the tax reform legislation could reduce the benefits of the Combined Projects. (Mullins Direct, page 40, lines 13–18.) Was the BEAT provision included in the final legislation enacted?

A. No.

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

A. Yes.