ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

May 15, 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 Utah Admin. Code R746-1-203 and the Order Granting Motion to Vacate Remaining Schedule and Amended Scheduling Order issued by the Utah Public Service Commission ("Commission") on February 13, 2018, in the above referenced docket, Rocky Mountain Power hereby submits for electronic filing its Surrebuttal Testimony to Rebuttal Testimony on RFP Results Filed on April 17, 2018.

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:

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

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

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

Sincerely,

Joelle Steward
Vice President, Regulation

CERTIFICATE OF SERVICE

Docket No. 17-035-40

I hereby certify that on May 15, 2018, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

Utah Office of Consumer Services	
Cheryl Murray (C) Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 cmurray@utah.gov	Michele Beck (C) Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 mbeck@utah.gov
Division of Public Utilities	
Erika Tedder (C) Division of Public Utilities 160 East 300 South, 4th Floor Salt Lake City, UT 84111 etedder@utah.gov	Consultants dpeaco@daymarkea.com (C) aafnan@daymarkea.com jbower@daymarkea.com
Assistant Attorney General	
Patricia Schmid (C) Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 pschmid@agutah.gov	Robert Moore (C) Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 rmoore@agutah.gov
Justin Jetter (C) Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 jjetter@agutah.gov	Steven Snarr (C) Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 stevensnarr@agutah.gov
Rocky Mountain Power	
Jana Saba 1407 W North Temple, Suite 330 Salt Lake City, UT 84114 jana.saba@pacificorp.com	Yvonne Hogle 1407 W North Temple, Suite 320 Salt Lake City, UT 84114 yvonne.hogle@pacificorp.com

Jeff Richards 1407 W North Temple, Suite 320 Salt Lake City, UT 84114 robert.richards@pacificorp.com	
Katherine McDowell McDowell Rackner Gibson PC 419 11th Avenue, Suite 400 Portland, Oregon 97205 katherine@mrg-law.com	Adam Lowney McDowell Rackner Gibson PC 419 11th Avenue, Suite 400 Portland, Oregon 97205 adam@mrg-law.com
Pacific Power	
Sarah K. Link Pacific Power 825 NE Multnomah St., Suite 2000 Portland, Oregon 97232 sarah.link@pacificorp.com	Karen J. Kruse Pacific Power 825 NE Multnomah St., Suite 2000 Portland, Oregon 97232 karen.kruse@pacificorp.com
Utah Association of Energy Users	
Gary A. Dodge (C) Hatch, James & Dodge, P.C. 10 West Broadway, Suite 400 Salt Lake City, UT 84101 gdodge@hjdlaw.com	Phillip J. Russell (C) Hatch, James & Dodge, P.C. 10 West Broadway, Suite 400 Salt Lake City, UT 84101 prussell@hjdlaw.com
Nucor Steel-Utah	
Peter J. Mattheis (C) Stone Mattheis Xenopoulous & Brew, P.C. 1025 Thomas Jefferson Street, N.W. 800 West Tower Washington, DC 20007 pjm@smxblaw.com	Eric J. Lacey (C) Stone Mattheis Xenopoulous & Brew, P.C 1025 Thomas Jefferson Street, N.W. 800 West Tower Washington, DC 20007 ejl@smxblaw.com
Jeremy R. Cook (C) Cohne Kinghorn 111 East Broadway, 11th Floor Salt Lake City, UT 84111 jcook@cohnekinghorn.com	
Interwest Energy Alliance	
Mitch M. Longson (C) Manning Curtis Bradshaw & Bednar PLLC 136 East South Temple, Suite 1300 Salt Lake City, UT 84111 mlongson@mc2b.com	Lisa Tormoen Hickey (C) Tormoen Hickey LLC 14 N. Sierra Madre Colorado Springs, CO 80903 lisahickey@newlawgroup.com

Utah Clean Energy	
Sophie Hayes (C) 1014 2nd Avenue Salt Lake City, UT 84111 sophie@utahcleanenergy.org	Kate Bowman (C) 1014 2nd Avenue Salt Lake City, UT 84111 kate@utahcleanenergy.org
Hunter Holman (C) Utah Clean Energy 1014 East Second Avenue Salt Lake City, UT 84105 hunter@utahcleanenergy.org	
Utah Industrial Energy Consumers	
William J. Evans Parsons Behle & Latimer 201 South Main Street, Suite 1800 Salt Lake City, UT 84111 bevans@parsonsbehle.com	Vicki M. Baldwin Parsons Behle & Latimer 201 South Main Street, Suite 1800 Salt Lake City, UT 84111 vbaldwin@parsonsbehle.com
Chad C. Baker Parsons Behle & Latimer 201 South Main Street, Suite 1800 Salt Lake City, UT 84111 cbaker@parsonsbehle.com	
Western Resource Advocates	
Jennifer E. Gardner (C) 150 South 600 East, Suite 2A Salt Lake City, UT 84102 jennifer.gardner@westernresources.org	Nancy Kelly (C) 9463 N. Swallow Rd. Pocatello, ID 83201 nkelly@westernresources.org
Penny Anderson penny.anderson@westernresources.org	Steve Michel steve.michel@westernresources.org

Jennifer Angell
Jennifer Angell
Supervisor, Regulatory Operations

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

Surrebuttal Testimony of Cindy A. Crane

May 2018

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

A. Yes.

PURPOSE AND SUMMARY OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. I support the Company's request for approval of its significant and voluntary resource decisions for the Ekola Flats, TB Flats I and II, and Cedar Springs new wind projects ("Wind Projects") and for the Aeolus-to-Bridger/Anticline transmission line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects"), as modified in this filing to remove the Uinta project from the requested approval. I also provide a policy response to the April 17, 2018 testimonies filed by the Division of Public Utilities ("DPU"), the Office of Consumer Services ("OCS"), and the Utah Association of Energy Users and the Utah Industrial Energy Consumers ("UAE/UIEC").

Q. Please summarize your testimony.

A. The Combined Projects are a time-limited resource opportunity that is part of the least-cost, least-risk portfolio to meet customers' resource needs. The costs and risks of the Combined Projects continue to decrease, confirming that the Company's resource decisions make sense for Utah customers. The 1,300 simulations performed by Company witness Mr. Rick T. Link thoroughly tested and confirmed the durability of the net benefits of the Combined Projects under a broad range of variables and uncertainties. The results demonstrate that the Combined Projects are in the public interest because they: (1) will most likely result in the acquisition, production, and delivery of service at the lowest reasonable cost to the customers; (2) serve customers' long-term and short-term interests; (3) minimize risk; (4) increase reliability; and (5) provide net benefits to customers without financial harm to the Company. The Company is withdrawing its request for approval of the Uinta wind project, to respond to parties' concerns and align this filing with the certificates for public and convenience ("CPCNs") issued in Wyoming, and the pending settlement in Idaho with commission staff. For these reasons, as explained in more detail below, and the reasons set forth in the Company's previously-filed testimony, the Combined Projects are prudent, in the public interest and should be approved.

UPDATE ON THE COMBINED PROJECTS

Q. Has the Company withdrawn the Uinta wind project from its request for resource approval?

A. Yes. The Company is now seeking resource approval for only three wind facilities, totaling 1,150 MW: (1) TB Flats I and II (500-MW benchmark project); (2) Cedar Springs (400-MW project, one-half build-to-own ("BTA"), one-half power-purchase agreement ("PPA"); and (3) Ekola Flats (250-MW benchmark project).

Q. Why did the Company narrow its request for significant resource approval?

A. In April 2018, the Company executed a stipulation with many parties in the Wyoming CPCN docket supporting issuance of CPCNs for the Combined Projects. In the stipulation, the parties agreed to remove the Uinta project. The Wyoming Public Service Commission approved the stipulation on April 12, 2018, and issued CPCNs for the Combined Projects, as modified to remove the Uinta project. The Wyoming CPCNs are conditioned on the Company obtaining rights-of-way, the status of which is addressed in the testimony of Mr. Chad A. Teply.

In May 2018, the Company executed a partial stipulation with the staff of the Idaho Public Utility Commission supporting the issuance of a CPCN and resolving all but one issue between the Company and Staff (whether or not an overall cost cap should apply to the Combined Projects.) That stipulation, now pending before the Idaho Commission after a hearing on May 10–11, 2018, also removed the Uinta project.

In this case, DPU witness Mr. Peaco raised concerns about the Uinta project. (Peaco Supplemental Rebuttal and Surrebuttal, lines 673–736.)

For all of these reasons, the Company removed the Uinta project from the Combined Projects in this case.

Q. Has the Company updated its filing to reflect this change?

A. Yes. Ms. Joelle R. Steward's surrebuttal testimony includes the updated, reduced overall costs for the Combined Projects and the updated revenue requirement impacts. Mr. Rick A. Vail supports the updated, reduced costs of the network upgrades. Mr. Link's testimony addresses the specific overall economics of the Combined Projects without Uinta.

THE COMBINED PROJECTS ARE IN THE PUBLIC INTEREST

Q. DPU, OCS, and UAE/UIEC claim that the Combined Projects are not in the public interest. (*See* Zenger Supplemental Rebuttal and Surrebuttal, lines 40–41; Vastag Second Rebuttal, lines 30–32; Mullins Supplemental Rebuttal, lines 49–51.) In your opinion, are the parties' concerns with the Combined Projects well-founded?

A. No. Although the parties criticize the Company for relying on allegedly speculative benefits, the parties' arguments largely ignore or dismiss the Company's factual evidence and robust analysis. The Company's economic analysis demonstrates—based on over 1,300 model simulations using conservative assumptions—that the Combined Projects are in the public interest and are most likely to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to customers. (Utah Code §§ 54-17-302, 54-17-402.) In addition, the following facts support a finding that the Combined Projects are in the public interest:

- It is clear that the Company has a capacity resource need today, which will persist even after the Combined Projects are added to the Company's generation portfolio. Thus, the real issue raised isn't whether there is a resource need, but rather whether the Combined Projects or some other option (such as front-office transactions) represent the least-cost, least-risk option to meet that need. This is discussed further by Mr. Link.
- There is a need for the Aeolus-to-Bridger/Anticline transmission line that is independent from the Wind Projects. This fact is discussed further by Mr. Vail.
- The Company has not "materially" altered its proposal over the course of this case and has been transparent about the fact that the request would evolve as the 2017R Request for Proposals progressed.
- The independent evaluators overseeing the 2017R Request for Proposals ("RFP") in Utah and Oregon concluded that the process was fair and supported the final shortlist of projects, as discussed in detail by Mr. Link.
- The Company has not "changed its story" from economic opportunity to need, as discussed in more detail by Mr. Link and Mr. Vail. These concepts

are not mutually exclusive. The Combined Projects are both needed *and* provide a time-limited economic opportunity. Even under the worst-case price-policy scenarios, customers will still receive the benefits of new zero-fuel-cost energy and much-needed transmission at a grossly discounted price due to the current (but limited) availability of federal production tax credits ("PTCs").

- The statutory construct in Utah, and the thorough oversight of this Commission, provide sufficient protections for customers from remaining risks. In addition, and contrary to some parties' claims, the Company has agreed to share in the risks that are within the Company's control.

Q. Why do you say that it is clear that there is a resource need today, and how does a finding of need affect this proceeding?

A. As discussed in more detail by Mr. Link, the Company is capacity deficient throughout the planning period. The parties assume that the Company will rely on front-office transactions to meet this need, and then claim that there is no such deficiency. This is true even though some parties have criticized the Company for many years for over-reliance on the market purchases to meet the Company's resource needs. But the 2017 Integrated Resource Plan ("IRP") selected the Combined Projects as part of the Company's portfolio of resources because they are lower cost and lower risk than market purchases and other resources. The analysis of the Combined Projects has continued throughout this proceeding and shows that the Combined Projects remain the lowest reasonable-cost option available, with the benefits improving and the costs declining as the case has progressed.

Almost all of the parties' arguments against the Combined Projects are premised on an alleged lack of need, including arguments that a heightened standard of review should apply. (*See, e.g.*, Peaco Supplemental Rebuttal and Surrebuttal, lines 136–150; Mullins Supplemental Rebuttal, lines 24–28.) Some of the witnesses even explicitly state that their positions would be different if there was a need for the resources. (*See, e.g.,* Peaco Supplemental Rebuttal and Surrebuttal, lines 136–150; Zenger Supplemental Rebuttal and Surrebuttal, lines 460–482; Hayet Second Rebuttal, lines 951–954.) Since there is a clear need, the Commission should reject these arguments.

Q. How has the Company's proposed resource decision to acquire the Combined Projects evolved from its initial filing in June 2017?

A. As indicated in the Company's initial filing, this time-sensitive opportunity required the Company to file its request for approval of the Combined Projects concurrently with its request for approval of the RFP. In its June 2017 filing, the Company informed the Commission and parties that it would supplement its filing once the results of the RFP were known. The Company supplemented its initial filing in January 2018, with the preliminary final results of its RFP process, and refined the final RFP results in its February 2018 filing. As the case has progressed through the past 12 months, the costs and benefits have become more well-defined and the risks have declined, demonstrating the improved economics of the Combined Projects.

Q. What are the requirements for approval of the Combined Projects under Utah Code Ann. §§ 54-17-302(3)(c) and 54-17-402(3)(b)?

A. I understand that the Commission must determine whether the resource decision is in the public interest, considering the following:

- Whether the decision will most likely result in the acquisition, production, and delivery of service at the lowest reasonable cost to the customers;
- Long-term and short-term impacts;
- Risk;
- Reliability;
- Financial impacts on the utility; and
- Other factors determined by the Commission to be relevant.

Q. Do the Combined Projects continue to meet the public interest standard considering the evaluation of the final RFP results and the Combined Projects' progressively well-defined economics and risks?

A. Yes. First, the 2017R RFP was monitored by two independent evaluators—one appointed by the Public Utility Commission of Oregon and one retained by this Commission. The independent evaluators monitored the 2017R RFP to ensure that the RFP was fair, unbiased, and conducted in the public interest. Both of these independent evaluators affirmed that the 2017R RFP process and results are in the public interest.

Second, the Aeolus-to-Bridger/Anticline line is a necessary investment for customers. The addition of this transmission line by 2024 is an important part of the Company's long-term transmission plan, and the line is needed to relieve congestion, provide voltage support, improve reliability, and reduce line losses. The robust response to the 2017R RFP, and the interconnection constraints faced by many of the bidders, reinforce the importance of adding more transmission capacity in eastern Wyoming to harness cost-effective generation resources for customers. The Wyoming Public Service Commission's approval of the Combined Projects confirms their agreement that Aeolus-to-Bridger/Anticline line is necessary for customers.

In addition, the Wind Projects are needed to provide zero-fuel-cost generation to serve customers, minimizing reliance on more-expensive front-office transactions and reducing net power costs. The Wind Projects provide significant benefits—which sum to approximately $1.2 billion over 10 years—from currently available PTCs. These benefits allow the Company to construct the Transmission Projects with small near-term rate increases and long-term savings. Since the Company's initial filing and the completion of the 2017R RFP, the near-term rate increases have remained modest, while the long-term benefits of the Combined Projects have increased and the risks have decreased. As explained further by Mr. Link, in the 18 scenarios studied (nine each for the 2050 and 2036 analyses) for the Combined Projects, 16 of 18 cases show net customer benefits. The Combined Projects (without Uinta) now show benefits of $174 million in the medium case through 2050, and benefits of $338 million in the medium case through 2036.

Q. Please summarize the conclusions of the Utah and Oregon independent evaluators regarding the 2017R RFP.

A. Both independent evaluators found that the 2017R RFP was conducted in a manner that produced the most competitive resource options for customers. The Utah independent evaluator specifically concluded that the 2017R RFP was fair, reasonable, and generally in the public interest. (Final Report of Merrimack Energy Group, Inc. to Utah Public Service Commission, PacifiCorp Renewable Request for Proposals (Feb. 2018) ("Utah IE Report"), Exhibit RMP__(RTL-2SR) at 70.) According to the independent evaluator, the RFP was designed to lead to the acquisition of wind-generated electricity at the lowest reasonable cost. (Utah IE Report, page 71.) The Company used a "detailed state-of-the-art portfolio evaluation methodology" demonstrating that the Combined Projects "should result in significant savings for customers," particularly in the near-term. (Utah IE Report at 71, 83.)

The Oregon independent evaluator concluded that the Wind Projects were the top viable offers and provide the greatest benefits to ratepayers. (Independent Evaluator's Final Report on PacifiCorp's 2017R Request for Proposal (Feb. 16, 2018) ("Oregon IE Report"), Exhibit RMP__(RTL-1SR) at 2–3.) The Oregon independent evaluator verified the Company's modeling with its own cost modeling of each bid and confirmed that the 2017R RFP aligned with the 2017 IRP. (Oregon IE Report at 2–3.)

Q. How did the independent evaluators conclude that the 2017R RFP was unbiased?

A. First, both independent evaluators conducted a detailed and independent assessment of the Company's benchmark resources. The Utah independent evaluator noted that the Company's benchmark information exceeded industry standards, the costs were reasonable, and there was no outward perception of bias. (Utah IE Report at 44–45.) The Oregon independent evaluator stressed that he took special care to confirm the selection of the benchmark resources, that the benchmark costs were disciplined by third-party bids for the same resources, and that his thorough assessment concluded that the benchmark costs were reasonable. (Oregon IE Report at 2–3, 10–11.)

Second, to confirm that there was no bias, the Oregon independent evaluator requested that the Company perform a sensitivity analysis to compare the Company's selected bids to an alternative portfolio of PPAs, as described in Mr. Link's supplemental direct and rebuttal testimony. (Link Supplemental Direct and Rebuttal, lines 252–277.) Both independent evaluators agreed that the results of this sensitivity showed that there was no bias. (Oregon IE Report at 32; Utah IE Report at 62–63.)

Q. Did the independent evaluators address the modeling and evaluation issues raised by the parties in this case?

A. Yes. Nearly every criticism leveled at the Company's solicitation process or modeling in the parties' testimony was addressed and rejected by the independent evaluators:

- The independent evaluators confirmed that the Company's refined modeling of PTC benefits to match how PTCs flow through rates did not bias the bid selection in favor of utility-owned resources.
- The independent evaluators reviewed the Company's solar sensitivity related to the 2017S RFP and neither disputed the Company's conclusion that solar resources do not displace the Wind Projects—meaning that wind and solar resources are not an either-or proposition.
- The independent evaluators confirmed that the Company's determination of project viability based on interconnection queue positions was reasonable.
- The independent evaluators confirmed the accuracy of the Company's terminal value benefits used to evaluate utility-owned resources, and both further noted that the benefit was modest.

Q. OCS and DPU allege that the Company is not assuming sufficient risks of the Combined Projects. (Hayet Second Rebuttal, lines 928–947; Peaco Supplemental Rebuttal and Surrebuttal, lines 275–305.) How do you respond?

A. Since the case was filed almost 12 months ago, the risks have decreased. The Company's economic analysis shows that in almost every future scenario, customers are better off with the Combined Projects than under the status quo (which requires greater reliance on the market, coupled with future acquisitions of non-PTC-eligible resources). Further, I understand Utah's statutes governing approval of resource decisions provide substantial customer protections against cost overruns by imposing a soft cost cap on recovery. (*See* Utah Code Ann. §§ 54-17-303 and -403.) Additionally, the Company has consistently asserted it will take every precaution to ensure that the Wind Projects meet the requirements and timelines to qualify for full PTC benefits and are prepared to accept risks associated with our performance.

The Company's assumption of project risks has also been more explicitly defined, as described by Mr. Teply and Ms. Steward. Generally, the Company will assume all risks associated with the qualification of PTCs with the exception of a force majeure event or a change of law. If there is a dispute on whether either of these triggering events has occurred, my understanding is that Utah Code Ann. § 54-17-304 (for requests for approval of a significant resource decision) and § 54-17-404 (for requests for approval of a voluntary resource decision) include a process for a change in circumstances, such as a force majeure event. This will give parties an opportunity to review the Company's position that a change in circumstances has occurred.

Q. Several parties suggest that solar PPAs resulting from the 2017S RFP may be a lower cost alternative to the Combined Projects. (*See, e.g.*, Mullins Supplemental Rebuttal, lines 368–370.) How do you respond?

A. Mr. Link's economic analysis refutes this claim. His analysis demonstrates that solar resources are best viewed as an incremental opportunity, not as an alternative to the Combined Projects. Mr. Link's testimony outlines the unique valuation risks associated with solar resources, which dramatically reduce the expected customer benefits associated with the solar PPAs resulting from the 2017S RFP. Moreover, if the construction of the Aeolus-to-Bridger/Anticline transmission line is included in the base case modeling in the 2050 analysis—consistent with the Company's and region's current long-term transmission plan—then the net benefits of the Combined Projects would be nearly $300 million higher than the solar PPAs in all cases. In addition, there is no immediate need to act to secure the potential tax benefits of solar resources. The Company intends to continue to evaluate solar resources in its 2019 IRP and in bilateral negotiations, building off the results of the 2017S RFP. In contrast, if the Company does not move forward on the Combined Projects now, it will lose the substantial customer savings resulting from the acquisition of PTC-eligible wind resources.

CONCLUSION

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
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

REDACTED
Surrebuttal Testimony of Chad A. Teply

May 2018

Q. Are you the same Chad A. Teply who previously submitted 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 surrebuttal testimony in this proceeding?

A. I support the Company's proposal to construct and 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"), by responding to the supplemental rebuttal and surrebuttal testimony submitted by the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Mr. Daniel Peaco, and Mr. Charles E. Peterson, and the second rebuttal testimony of Office of Consumer Services ("OCS") witness Mr. Philip Hayet.

Q. Please summarize your testimony.

A. As development activities and contract negotiations progress, the Company continues to prudently and successfully mitigate many of the risks of the Wind Projects that the other parties discuss in their testimony, and the Combined Projects continue to fit squarely within the public interest. The Company has made excellent progress in its negotiations with counterparties in support of all of the Wind Projects since its February 2018 supplemental direct and rebuttal testimony filing. I will provide status updates and additional information on the nominal 500-MW TB Flats I and II, the nominal 250-MW Ekola Flats, and the nominal 400-MW Cedar Springs projects in this testimony. As discussed by Company witness Ms. Cindy A. Crane in her surrebuttal testimony, to address intervenor concerns (*see, e.g.,* Peaco Supplemental Rebuttal and Surrebuttal, lines 673-736) and align the request before this Commission with the stipulations in Wyoming and Idaho, the Company is removing the nominal 161-MW Uinta project from the Wind Projects for which the Company is seeking approval.

The Company has continued to prudently adjust its development and negotiations schedules for the Wind Projects to accommodate changing procedural schedules across our various ongoing parallel-path regulatory proceedings. While Dr. Zenger characterizes these schedule adjustments as a failure to maintain project schedules and introduction of additional project risks (Zenger Supplemental Rebuttal and Surrebuttal, lines 409–419), that simply is not the case. The Company has successfully accommodated changing regulatory schedules through its positive working relationships with shortlisted counterparties to ensure that the results of ongoing regulatory proceedings can be accommodated in final definitive agreements. The off-ramps the Company has committed to maintain as the Combined Projects are reviewed and implemented remain viable through this early project-development timeframe. These types of implementation activities are typical of any project-development process and, as discussed in my previous testimony in this docket, the Company has extensive experience addressing and mitigating risks associated with project development.

Following completion of the 2017R Request for Proposals process, and as final contract negotiations progress, the cost and commercial risks associated with the Combined Projects continue to decrease. The Company is engaged in negotiation of definitive engineering, procurement, and construction ("EPC") contracts with the selected contractor, as well as final turbine-supply agreements ("TSA"), for the 500-

MW TB Flats I and II project and the 250-MW Ekola Flats project. The Company is also engaged in negotiation of definitive agreements for the 200-MW build-transfer agreement ("BTA") and the 200-MW power-purchase agreement ("PPA") for the Cedar Springs project. All key counterparties for these Wind Projects have now been selected and firm competitive market pricing for these projects has been received. Because the Company withdrew the request for a certificate of public convenience and necessity ("CPCN") for the 161-MW Uinta project in the Wyoming Public Service Commission proceeding, negotiation of a definitive BTA for that project has been suspended.

Overall, the Company continues to timely develop and implement the Wind Projects with a focus on delivering customer benefits, while retaining the level of transparency regarding procurement, development, and permitting activities for the Wind Projects as originally committed to in our application in this docket. The Company objects to the conditions proposed by OCS witness Mr. Hayet as unnecessary, unprecedented, and beyond the regulatory compact.

RISKS OF COST OVERRUNS ARE OVERSTATED AND HAVE BEEN MITIGATED

Q. Dr. Zenger, Mr. Peaco, and Mr. Hayet state that the Company should be willing to bear the risk of construction delays and cost overruns. (Zenger Supplemental Rebuttal and Surrebuttal, lines 457–459; Peaco Supplemental Rebuttal and Surrebuttal, lines 1252–1269; Hayet Second Rebuttal, lines 958–962.) Has the Company stated its willingness to do so?

A. Yes. Contrary to the parties' contentions, the Company has committed and remains committed to bearing the consequences of construction delays or cost overruns that are in the Company's control, including the risk of delivering the Wind Projects in a manner that ensures eligibility for production tax credits ("PTCs"). This commitment is further described by Ms. Crane and Company witness Ms. Joelle R. Steward in their respective testimonies in this docket.

While a hard cap at current estimates with no opportunity for recovery of prudently incurred costs above the hard cap is not appropriate for major projects at this stage of development and implementation (meaning the pre-approval stage), the Company is committed to prudently managing unforeseen circumstances to deliver the Combined Projects and presenting its case for recovery, recognizing that the Commission will ultimately determine whether any such actions and costs were prudently deployed. The Company has historically prudently managed very similar projects through development, implementation, and operation, and the Commission should have the opportunity to review all costs incurred to implement the Company's resource additions. Furthermore, the statutory construct in Utah already provides customers with protection from imprudent cost overruns, as discussed later in my testimony and by Ms. Crane and Ms. Steward.

Q. What conditions has the Company placed on the controllable risks discussed above?

A. The Company conditioned its guarantee to provide PTC-eligible Wind Projects to activities for which the Company can control, clearly noting exceptions for force majeure and changes in law. The Company will present the facts and circumstances associated with either of these conditions, should they arise, for prudence review by the Commission. This condition, however, would not alter the Company's commitment and responsibility to, in conjunction with its contractors and counterparties, take commercially reasonable efforts to mitigate any impacts on the Combined Projects from a force majeure event or a change in law.

Q. Mr. Hayet claims the Company refuses to extend the assumption of risk for cost overruns caused by its contractors. (Hayet Second Rebuttal, lines 939–942.) Is this correct?

A. No. Mr. Hayet relies on the Company's response to OCS data request 16.7 in making this assertion, claiming that in that response the "Company essentially explained that if the transmission delay is caused by the performance of one of its contractors, PacifiCorp should not be held responsible for that." (Hayet Second Rebuttal 939–941.) But Mr. Hayet completely misstates the Company's response, which is attached to this testimony as Exhibit RMP ___(CAT-1SR). In that data request, OCS asked whether the Company was willing to absorb the risk of loss of receiving full PTC benefits if the Company needs to use the round-robin approach to operate the Wind Projects. The Company responded that use of the round-robin approach—in and of itself—would not indicate that the Company's performance was less than adequate, and therefore all circumstances would need to be considered to determine whether any loss of PTC eligibility was due to Company performance or due to some other factor. The Company did not disavow responsibility for its contractor's actions in the response—in fact, contractors are not even mentioned.

Q. Have the size and locations of the Wind Projects changed "materially" over the course of this case as Mr. Peaco claims (*see, e.g.*, Peaco Supplemental Rebuttal and Surrebuttal, lines 601–603)?

A. No. Two of the three Wind Projects (Ekola Flats and TB Flats I and II) are the same size and in the same location as when the projects were presented as benchmarks in the Company's initial filing. The table attempting to show the material differences in size in Mr. Peaco's testimony shows this consistency. (Peaco Supplemental Rebuttal and Surrebuttal, page 30, Table 2; *see also*, Hayet Second Rebuttal, page14, Table 1.) The third project—Cedar Springs—is located in eastern Wyoming, which is not surprising and is consistent with the Company's 2017 IRP and the Company's initial filing. Table 1 below shows that the size changes are not as drastic as the parties claim:

TABLE 1

	Direct	Supplemental Testimony	2nd Supplemental Testimony	Surrebuttal Testimony
McFadden Ridge II	110	109	--	--
Ekola Flats	250	---	250	250
TB Flats I and II	500	500	500	500
Cedar Springs	--	400	400	400
Uinta	--	161	161	--
Total	860	1,170	1,311	1,150

Q. Dr. Zenger states that the Company's changes to the final shortlist have caused "large cost differences" that make it "unreasonable to expect that other elements of the cost-benefit projection will not shift significantly in coming years." (Zenger Supplemental Rebuttal and Surrebuttal, lines 239–247). Is this a fair statement?

A. No. The Company has been clear from the beginning of this case that the costs of the Wind Projects would change as the 2017R RFP process progressed. Dr. Zenger's position is based on her statement that the "total projected capital costs increased by $345 million in the span of two months, between the January and February filing." (*Id.*, lines 239–240.) Although Dr. Zenger recognizes that the capital cost increase was due to the removal of McFadden Ridge II (a 109-MW project) and the addition of Ekola Flats (a 250-MW project), Dr. Zenger treats the increase as the result of poor cost estimation, hinting that cost could shift further in the future. But this is not a reasonable conclusion. The cost estimates for the benchmark projects that were presented as proxies in our initial filing, then ultimately selected in the 2017R RFP, have not changed significantly and, in fact, the costs of owned resources have decreased on a per-kilowatt basis by [redacted] percent over the course of this case, as discussed further by Company witness Mr. Rick T. Link.

Q. Dr. Zenger also expresses concerns that all of the contracts are not yet final, claiming this creates cost uncertainty. (Zenger Supplemental Rebuttal and Surrebuttal, lines 77–79, 300–301.) Is this consistent with DPU's position in past cases?

A. No. Dr. Zenger's concern that all of the contracts are not yet final is inconsistent with DPU's prior testimony in a different case. The case involved the installation of selective catalytic reduction systems at the Jim Bridger plant, and DPU testified that executing all contracts before filing for pre-approval created risk:

> [A] sequential process starting with the Company's RFP for EPC contractors and ending with an order in the pre-approval process could easily take up to a year or more. Requiring an EPC bidder to honor its price and other bid features for that long would likely put the bidder in an untenable position. For example, commodity prices, as we have seen, can move substantially in a short period causing the bidder's construction costs to also move substantially. The Company appears to have mitigated this risk and possibly enhanced the competitiveness of its bidding process by running the two processes—the RFP for EPC contractors and the pre-approval process—simultaneously. Therefore, the Division believes that conditional approval of the Company's decision as previously discussed is a reasonable approach and would be in the public interest.

In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4, Docket No. 12-035-92, DPU Exhibit 1.0 Dir, lines 89–98 (Nov. 20, 2012.) In this case, the Company has taken the same approach that DPU previously supported to mitigate customer risk.

Q. Mr. Peterson cites the Utah independent evaluator's concerns that the capital costs for the one of the benchmark bids was significantly lower than any of the BTA bids, requiring greater scrutiny. (Peterson Supplemental Rebuttal and Surrebuttal, lines 235–245.) How do you respond?

A. The Company believes that its competitive market engagement of top tier EPC contractors and wind turbine generator suppliers prior to submitting its proposals for the benchmark bids to the 2017R RFP actually reflects a greater level of scrutiny and confirmation than the BTA bids submitted into that process. While the Company was able to incorporate significant cost reductions in its benchmark proposals, as described above, as compared to the proxy project cost information submitted in our initial filing, those cost reductions were a direct result of the Company's efforts to formally engage the competitive market in support of its benchmark proposals. The Company has additionally restated its commitment to prudently managing unforeseen circumstances to deliver the Combined Projects and present its case for recovery, recognizing that the Commission will ultimately determine whether any such actions and costs were prudently deployed.

Q. Has the Company continued to confirm its cost assumptions and commercial terms and conditions for the Wind Projects since its February 2018 supplemental filing?

A. Yes. The Company is currently finalizing its EPC contracts for the TB Flats I and II and the Ekola Flats projects with a target date to have executable agreement in hand by May 31, 2018, and its TSA contracts for those projects by June 15, 2018. This date is indeed different than the date shown in the project-implementation timeline in my February 2018 testimony, as Dr. Zenger notes (Zenger Supplemental Rebuttal and Surrebuttal, lines 412–413), but has been intentionally adjusted by the Company and its counterparties to remain aligned with the all of the procedural schedules for the regulatory review of the Combined Projects and to ensure that final agreements can be informed by the results of our regulatory reviews.

Similarly, the Company is currently negotiating the BTA and PPA contracts for the Cedar Springs project with a target date for an executable agreement by July 15, 2018. This date allows time to have the respective commission orders in hand before execution and also provides for internal approval schedules that this specific counterparty must manage as part of its corporate governance.

In each case, these target dates continue to fully support in-service dates for the Wind Projects by year-end 2020 as currently contemplated in ongoing negotiations:

TB Flats I and II:

- Firm price EPC and TSA offers received/complete;
- Executable EPC contract by May 31, 2018;
- Executable TSA contract by June 15, 2018;
- Full notice to proceed by April 1, 2019;
- Contract in-service date November 15, 2020.

Ekola Flats:

- Firm price EPC and TSA offers received/complete;
- Executable EPC contracts by May 31, 2018;
- Executable TSA contract by June 15, 2018;
- Full notice to proceed by April 1, 2019;
- Contract in-service date November 15, 2020.

Cedar Springs:

- Firm price BTA offer received/complete;
- Executable BTA contract by July 15, 2018;
- BTA firm / pre-closing date by July 1, 2019;
- Contract in-service / closing date November 26, 2020.

Q. Has the Company been granted conditional CPCNs for the Combined Projects since its February 2018 supplemental filing in this docket?

A. Yes. The Company received conditional CPCNs for the Combined Projects from the Wyoming Public Service Commission via bench order on April 12, 2018. As requested and expected**,** the CPCNs are conditioned upon the Company obtaining the necessary rights-of-way to construct the respective projects. There is no new risk here, with majority of rights-of-way for the Wind Projects already secured and rights-of-way acquisition for the Transmission Projects well underway. The timeline for the Combined Projects continues to support a reasonable schedule for rights-of-way acquisition and the appropriate off-ramps for the Combined Projects should the costs of rights-of-way acquisition materially reduce customer benefits or the timing of acquisition create unacceptable schedule risk. Of most significance, the Combined Projects' critical-path schedule requires the ability to provide full notice to proceed for the 140-mile, 500 kV transmission line portion of the Transmission Projects by April 1, 2019.

Q. Are the remaining permits that Dr. Zenger identifies as critical outstanding risks (Zenger Supplemental Rebuttal and Surrebuttal, lines 409–427) being actively managed as part of the normal course of development of the Combined Projects?

A. Yes. In alignment with the timelines for the Combined Projects, the Company and individual developers of the Wind Projects are actively engaged with state and local permitting agencies in developing the appropriate permit applications and procedural schedules. For each of the Combined Projects, the agencies have been directly engaged to identify and facilitate the most workable procedural schedules and to ensure that the level of project information provided best facilitates timely and successful review. In general, the permitting agencies feedback has been positive and supportive of the Combined Projects to date.

In particular, the currently contemplated application and hearing timeframes for the Combined Projects with the Wyoming Industrial Siting Division ("ISD") are as follows:

Transmission Projects

- ISD application to be filed July 19, 2018;
- ISD hearing anticipated October 15-19, 2018.

TB Flats I and II:

- ISD application filed March 27, 2018;
- ISD hearing anticipated June 21-22, 2018.

Ekola Flats:

- ISD application to be filed June 11, 2018;
- ISD hearing anticipated September 6-7, 2018.

Cedar Springs:

- ISD application to be filed by March 25, 2019;
- ISD hearing anticipated by June 20-21, 2019.

Applications for county conditional use permit and hearing timeframes are also being established.

While Dr. Zenger argues that the Company is over-optimistic with its efforts to mitigate permitting and other remaining project risks, the first-hand experiences of the Company representatives responsible for delivering these individual work scopes, and their engagements with counterparties on these activities, continue to support the Company's perspective.

Q. Dr. Zenger expresses concerns based on the opposition of several landowner intervenors in the Wyoming CPCN proceeding. (Zenger Supplemental Rebuttal and Surrebuttal, lines 427–452.) Please describe the Company's experience with the landowner intervenors in that docket.

A. While the list of intervenors that participated in the Wyoming CPCN proceeding did indeed include the six entities identified by Dr. Zenger (Rock Creek Wind, LLC intervened as a 2017R request for proposals participant and subsequently withdrew), the Company successfully engaged all of the landowner intervenors except one and reached preliminary agreements regarding rights-of-way acquisition terms and conditions. These successful discussions allowed all but one of the landowner intervenors to withdraw from the CPCN proceeding before its conclusion. The Company remains engaged with the sole remaining landowner intervenor from the Wyoming CPCN proceeding, as well as the other identified landowners associated with the Combined Projects, and fully understands the complexities of rights-of-way acquisition. The Company continues to believe that its rights-of-way acquisition experience, approach, and schedule will prove successful. If rights-of-way acquisition requires litigation, the Company has allowed reasonable time for that process. The Company is also maintaining the Combined Projects timeline to include off-ramps if rights-of-way acquisition is not successful.

Q. Dr. Zenger raises a concern with the Company's assumption of a 30-year wind project life. (*See* Zenger Supplemental Rebuttal and Surrebuttal, lines 343–356.) Has the Company assessed the viability of a 30-year wind project life assumption?

A. Yes. In fact, Dr. Zenger also acknowledges that the Company's currently approved wind resource depreciable life for Utah ratemaking purposes is 30 years. The Company continues to believe that 30 years is appropriate. While Dr. Zenger raises the possibility that this could change in the future, she provides no evidence that 30 years is unreasonable or technically infeasible. Instead, Dr. Zenger notes that there are other projects in the United States using 25-year lives. But there are also other projects that use longer depreciable lives. (*See, e.g.*, S&P Global—Platts, "Iowa Regulator Backs 2,000-MW MidAmerican Wind Energy Project," August 29, 2016 [noting a 40-year depreciable life for the wind projects].)

Q. Dr. Zenger also states that there is a potential risk of investing prematurely in new wind projects when the industry is experiencing rapidly changing technologies. (Zenger Supplemental Rebuttal and Surrebuttal, lines 362–365.) Is investment in the Wind Projects premature?

A. No. In fact, with each new generation resource project, the Company has historically deployed the then-current, commercially proven technology resources, whether renewable or natural-gas fueled. Recognizing that the Company will be serving the energy needs of its customers for decades to come, we fully expect and hope that technology improvements and cost reductions will continue to be identified as generation resource needs are identified and implemented in the future. The Combined Projects timeline, however, presents a single point in time for our customers to benefit from currently available production tax credits and currently available, commercially proven wind-turbine equipment. Technologies are always developing over time; it is not feasible or reasonable to chronically delay action to wait for the next round of technological developments. At some point—based on resource need and economics—the decision that acting now is prudent and in the best interest of customers must be made. For wind technology, that time is now, while full PTCs are available to reduce the costs of these zero-fuel-cost renewable resources for customers.

Q. Mr. Hayet proposes several conditions for the Commission to require of the Company under any approval of the Combined Projects, including a recommendation to impute a 95 percent of estimate capacity factor guarantee, limitations on initial capital cost recovery, and limitations on future O&M and capital expenses. (Hayet Second Rebuttal, lines 958–976.) Do you agree with Mr. Hayet's proposed conditions?

A. No. Requiring the Company to guarantee these future outcomes is an unnecessary, unprecedented, and unsupported set of conditions that goes well beyond the existing regulatory compact.

Q. Is Mr. Hayet's recommended guarantee of 95 percent of estimated capacity factor reasonable?

A. No. I addressed capacity-factor guarantees in my rebuttal testimony, explaining why the imputation of the estimated capacity factor is unreasonable. (Teply Supplemental

Direct and Rebuttal, lines 575–626.) The Company has used the best information currently available and industry-recognized methodology to estimate the production of the new Wind Projects. Actual wind production is an example of an item beyond the Company's control and inherently variable, as would be expected when using an annual 50-percent probability ("P50") approach. The Company and this Commission have administered the variability of the Company's existing wind fleet consistently using this approach within the existing regulatory compact over the last decade of operational life for the Company's existing wind resources.

Q. Is Mr. Hayet's condition on initial capital-cost recovery reasonable?

A. No. I have discussed my objection to a hard cap set at the cost estimates in this case earlier in testimony. (*See, e.g,* Teply Supplemental Direct and Rebuttal, lines 558–574.) To expand on those arguments, the Company prudently and ardently negotiates its contract terms and conditions to mitigate many of the risks discussed by the intervenors in this case. For example, the EPC, TSA, and BTA agreements for the Wind Projects will have robust risk-mitigation provisions, including fixed construction costs, terms and conditions to guarantee on-time delivery of the resources, counterparty representations and warranties, and commercially available indemnities and securities. The Company is currently engaged with each of the Wind Project developers, and with the EPC contractors and wind-turbine-generator suppliers, to finalize definitive agreements in parallel with the ongoing regulatory reviews of the Combined Projects.

The Company is also continuing with its engagement and support of each of the Wind Projects as their individual project-development activities continue with state and local permitting activities, public outreach, engagement of state and federal wildlife agencies, as well as landowners, leaseholders, and affected mineral rights holders, where applicable.

Nonetheless, even with all of these Company efforts and the expertise and experience of the Company and its contractors and counterparties, there may still be circumstances that results in costs above current estimates. The statutory construct in Utah sets a soft cap at the estimates in this case, then allows the Company to show that any cost overruns were prudent. (*See* Utah Cod Ann. § 54-17-303(1)(c)). Contrary to parties' arguments, the risks of cost overruns are the Company's unless and until this Commission finds that those costs were prudently incurred. This statutory construct protects customers, and no hard cap or other protections are necessary.

Q. Can the Company also use contracting to mitigate the risk of greater-than-expected operational expenses and reduced equipment availability through the life of the Wind Projects?

A. Yes. The Company intends to negotiate third-party maintenance contracts for the Wind Projects that will address operations and maintenance cost and run-rate capital expenditure risks for the Wind Projects. The Company will also negotiate availability guarantees for the Wind Projects in any third-party-provided maintenance agreements, as provided by the competitive market. In the Company's ongoing wind repowering project negotiations, the Company secured performance guarantees established at a production rate of 97 percent of the site potential energy available, based on the wind conditions experienced. It is reasonable to expect that similar guarantees can be negotiated for the Wind Projects. While the Company cannot guarantee future outcomes, development of the Wind Projects will include these important risk-mitigation measures, similar to those that have been included to support past investments.

CONCLUSION AND RECOMMENDATION

Q. What do you conclude in your surrebuttal testimony?

A. The Company continues timely develop and implement the Wind Projects with a focus on delivering customer benefits, while retaining the level of transparency regarding procurement, development, and permitting activities for the Wind Projects as originally committed to in our application in this docket. The Company continues to successfully mitigate the Wind Projects' cost and commercial risks that the DPU witnesses discuss in their testimony, and the Combined Projects continue to be prudent and fit squarely within the public interest. The conditions proposed by Mr. Hayet are unnecessary, unprecedented, and unsupported, with no basis to upend the traditional regulatory compact as it pertains to the Combined Projects having been presented. The Company respectfully requests the Commission's approval of the Combined Projects.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Chad A. Teply

Company’s Response to OCS 16.7

May 2018

17-035-40 / Rocky Mountain Power
March 26, 2018
OCS Data Request 16.7

OCS Data Request 16.7

Refer to the Company's response to UIEC 2.3. Ms. Crane has stated that PacifiCorp is willing to accept risks for the loss of receiving full PTC benefits associated with PacifiCorp's performance. Please confirm that the Company is not willing to absorb the risk of loss of receiving full PTC benefits if the Company operates the new wind units in the round robin scheme? Please fully clarify the risks that the Company is and is not willing to accept concerning the round robin scheme.

Response to OCS Data Request 16.7

The use of a "round robin" scheme does not, by itself, indicate that the Company's performance was less than adequate or that the Company is or is not solely responsible for the lost production tax credits (PTC) during the rotating curtailment. An assessment of the circumstances that brought about the need to use a "round robin" scheme and the Company's performance in light of those circumstances would be necessary to determine the responsibility.

Regarding risks that the Company is and is not willing to accept concerning a "round robin" scheme, the Company objects to the request on the basis that it calls for speculation. Any outcome that is less than favorable would need to be assessed as to whether the outcome was a result of Company's performance or whether an outcome was a result of factors outside of the Company's ability to influence.

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
Surrebuttal Testimony of Rick A. Vail

May 2018

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

A. Yes.

PURPOSE AND SUMMARY OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. My testimony further supports the Company's voluntary request for approval of a resource decision to construct the Aeolus-to-Bridger/Anticline transmission line and network upgrades ("Transmission Projects"). Specifically, my testimony responds to the April 17, 2018, testimonies filed by Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger and Mr. Daniel Peaco, Office of Consumer Services ("OCS") witness Mr. Philip Hayet, and the Utah Association of Energy Users ("UAE") and the Utah Industrial Energy Consumers ("UIEC") witness Mr. Bradley G. Mullins.

Q. Please summarize your testimony.

A. Many—if not most—of the parties' concerns in this case are based on a misunderstanding or mischaracterization of the Company's testimony to date, particularly regarding the Company's transmission studies, services, and processes. In my surrebuttal testimony, I first discuss the continued and immediate need for the Transmission Projects. The transmission system in eastern Wyoming is currently constrained, with generation capacity behind the TOT 4A cut-plane exceeding transmission capacity. The Aeolus-to-Bridger/Anticline transmission line has been part of the Company's long-term transmission plan since 2007 and provides substantial immediate benefits with or without the Wind Projects (Ekola Flats, TB Flats I and II, and Cedar Springs). The advantage of building the Transmission Projects along with the Wind Projects is the economic benefits to customers that will be realized over the life of the projects.

Second, I demonstrate that the Transmission Projects' risks have decreased over the course of this case. Project costs are now more certain, and final contracting and construction is on-schedule; the Company has made substantial progress scoping, developing, and preparing the projects to submit the next round of permit applications necessary for construction and operation. Based on its extensive experience developing comparable transmission resources, the Company is confident that it can deliver the Transmission Projects on-time and at the cost estimates included in my testimony.

Third, the Company did not mismanage its generator interconnection queue or attempt to use its generator interconnection queue to bias the outcome of the 2017R Request for Proposals ("RFP"), as certain parties assert. The Company's treatment of all projects in its generator interconnection queue, whether bidders or not, was consistent with the terms and conditions of its Open Access Transmission Tariff ("OATT").

Fourth, the detailed technical analysis of the Transmission Projects continues to improve and demonstrate that the Company can reliably interconnect the Wind Projects while increasing the transfer capability across Wyoming.

Finally, the Company's estimated third-party transmission revenues included in the economic analysis are reasonable and consistent with the ratemaking methodologies used by the Federal Energy Regulatory Commission ("FERC").

REMOVAL OF UINTA

Q. As discussed by Company witness Ms. Cindy A. Crane, the Company has removed Uinta from the list of projects for which the Company is seeking approval. Does this change affect the network upgrades?

A. Yes. Exhibit RMP___(RAV-1SR) shows the updated 230-kV network upgrades. The following upgrades will no longer be needed with the removal of the Uinta project:

- Construct a new three (3) breaker 230-kV ring bus.
- Inclusion of the project into Naughton RAS.
- Construct a 230-kV single circuit transmission line beginning approximately one mile outside of the Ben Lomond substation to replace the Ben Lomond–Naughton 230-kV #1 circuit which resides on the north side of the 7-mile long lattice tower double circuit with the Ben Lomond–Birch Creek 230-kV line.
- Reconductor 2.35 miles of 795 ACSR 138-kV line between Railroad and Croydon with 1222 ACCC high temperature conductor. The portion of the line to reconductor is on one side of a double-circuit tower.

Q. How do these changes to the network upgrades affect the cost of the Transmission Projects?

A. The costs are reduced by $33.33 million, from $110.65 million to $77.32 million.

TRANSMISSION PROJECTS ARE NEEDED AND WILL PROVIDE IMMEDIATE BENEFITS TO CUSTOMERS

Q. The parties assert that the Company did not claim that it had a need for the Aeolus-to-Bridger/Anticline transmission line until late in this proceeding and has not established any independent need for the line. (***See, e.g.*****, Peaco Supplemental Rebuttal and Surrebuttal, lines 193–205.) Is this a fair characterization of the Company's testimony?**

A. No. The parties ignore the fact that the Company's direct and rebuttal testimonies thoroughly described the need for the Aeolus-to-Bridger/Anticline transmission line—with or without the Wind Projects. (Vail Direct, lines 72–83, 313–528; Vail Supplemental Direct and Rebuttal, lines 260–424.) As discussed further by Ms. Crane and Company witness Mr. Rick T. Link, the parties also ignore the Company's comments and testimony in the Utah proceeding approving the 2017R RFP, as well as the 2017 Integrated Resource Plan.

In my previously filed testimony, I explained that the Aeolus-to-Bridger/Anticline line is necessary to relieve *existing* congestion on the system and that without the new transmission line, the Company's ability to deliver resources to load will remain constrained. I further described how the North American Electric Reliability Corporation's and Western Electricity Coordinating Council's standards and criteria influenced the need for the Aeolus-to-Bridger/Anticline line. The Company made it clear that the Aeolus-to-Bridger/Anticline line has been an integral component of the long-term transmission plan for the region long before the Wind Projects were contemplated.

I then reiterated these points in my rebuttal testimony, responding explicitly to the argument that there was no need for the Aeolus-to-Bridger/Anticline line. As further explained in my rebuttal testimony, the Aeolus-to-Bridger/Anticline line and the Wind Projects are mutually dependent on one another because the Wind Projects affect the *timing* of the construction of the line and provide PTC benefits to offset the cost of the line, but contrary to assertions from Mr. Peaco, the Company did *not* testify that the *need* for the Aeolus-to-Bridger/Anticline line was related to the development of the Wind Projects. The parties ignore my rebuttal testimony entirely and, in doing so, mischaracterize the record on this point.

Q. Why are the Transmission Projects needed even without the Wind Projects?

A. The transmission system in eastern Wyoming is currently extremely constrained. Beyond one project with an in-service date before the end of 2020 and an interconnection agreement that allows interconnection without the Aeolus-to-Bridger/Anticline line, no additional generation can be reliably interconnected today. This means that additional generation cannot even "clamp on" to the Company's system, much less be reliably integrated and delivered to load.

Since 2007, PacifiCorp's integrated resource plans have identified that PacifiCorp's long-term transmission plan calls for the construction of multiple segments of Energy Gateway, including the Aeolus-to-Bridger/Anticline line. Although (as parties have pointed out, *see*, *e.g.*, Hayet Second Rebuttal, lines 867–875) the planned permitting and construction dates—which depend on variety of factors—have changed over time, the estimated outer range has consistently been 2024. The timeframe estimates, and the long-term transmission plan itself, take into account and are supported by many factors, including:

- Ensuring PacifiCorp's OATT network transmission customers can deliver their designated network resources to their designated network loads on a firm basis, as required by FERC;
- Accommodating requests for long-term firm point-to-point transmission service under PacifiCorp's OATT;
- Accommodating generator requests to interconnect with PacifiCorp's transmission system under the OATT; and
- The results of the coordinated local and regional planning process set forth in PacifiCorp's OATT Attachment K and primarily memorialized in the study plans issued by the Northern Tier Transmission Group ("NTTG").

In addition, generally speaking, the transmission system planning reliability standards set out detailed requirements for conducting annual studies to assess the performance of the transmission system over certain time horizons. While reliability standard studies of this nature are technically distinct from the transmission planning factors listed above, the information they provide about current system operations under a variety of conditions generally informs and supports PacifiCorp's long-term planning initiatives as well.

Furthermore, the Aeolus West Transmission Path Transfer Capability Assessment report, the most recent version of which is attached as Exhibit RMP___(RAV-2SR) and dated March 30, 2018, identifies all reliability standards that are required for construction of the Aeolus-to-Bridger/Anticline line and all performance standards that require the construction of the Aeolus-to-Bridge/Anticline.

Q. What other benefits do the Transmission Projects provide?

A. Independent of the need to integrate additional wind in eastern Wyoming, the Transmission Projects will provide the following reliability benefits to the transmission system:

- The projects will strengthen the overall reliability of the existing transmission system by providing critical voltage support to the Wyoming transmission network.
- The addition of new transmission lines will mitigate the impact of outages on the existing system, and will increase the system reliability under the various multiple contingencies of the North American Electric Reliability Corporation ("NERC") transmission planning TPL-001-4 standard.
- If there is a line outage, the redundancy provided by the projects will allow the Company to continue to meet native load service obligations and continue to meet other contractual obligations to third parties.
- The project will improve the Company's ability to perform required maintenance without significant operational impacts to the system, and will reduce impacts to customers during planned and forced system outages.

In addition to reliability benefits, the Transmission Projects will also:

- Increase the transfer capability across Wyoming by 951 megawatts ("MW") and enable interconnection of the proposed Wind Projects;

- Reduce congestion on the heavily used transmission system in Southeast Wyoming;
- Provide greater flexibility in managing existing resources and reduce energy and capacity losses; and
- Support the long-term transmission expansion planning established in the most recent NTTG Regional Transmission Plan.

Q. Mr. Peaco claims that the Company has "historically" relied on "economic justifications" to build new transmission, including the Aeolus-to-Bridger/Anticline line, and that no economic justification for the projects would exist without the Wind Projects. Is this correct?

A. No. Mr. Peaco cites to the Company's integrated resource plans ("IRPs") to support his statements. But whether or not transmission projects are needed is not determined in an IRP. Instead, it is determined through the long-term transmission plans that Mr. Peaco dismisses. (Peaco Supplemental Rebuttal and Surrebuttal, lines 250–261.) The IRP process is focused on determining the least-cost, least-risk portfolio of *generation* resources needed to serve load. While some regulatory commissions require consideration of transmission needs in an IRP, including these needs in an integrated resource plan is problematic from my perspective because the benefits of new transmission are often not quantifiable, making it difficult to demonstrate that transmission is cost-effective in the context of an IRP. But the Company's long-term transmission planning *does* consider reliability requirements and FERC precedent that can require a line to be built regardless of economics (see the factors listed above, lines 111–120), which are what primarily drive the need for transmission investments.

Q. Has DPU previously supported the use of long-term transmission planning to justify the construction of transmission resources?

A. Yes. In the Company's 2015 IRP docket, DPU's comments indicated: "In spite of delays, the Energy Gateway strategy is a fundamental part of the Company's long-term plan for existing and future customers, and the Division stresses the importance of transmission planning because of its long lead time." *In the Matter of PacifiCorp's 2015 Integrated Resource Plan*, Docket No. 15-035-04, Division Comments at 12 (June 29, 2016).

Q. Mr. Peaco states that you provided no information regarding how the Aeolus-to-Bridger/Anticline transmission line would be "economically justified solely for the reliability and system performance improvements [you] described." (Peaco Supplemental Rebuttal and Surrebuttal, lines 218–221.) Does Mr. Peaco accurately state the drivers for investing in new transmission infrastructure?

A. No. As mentioned above, the need to for new transmission infrastructure is driven by reliability requirements and FERC polices and precedent, not economics. The fact that the Company tries to find ways to reduce the impact of transmission investments on its customers by finding alternatives to delay those investments as long as possible or, as in this case, use the availability of federal tax credits to reduce the rate impact of transmission investment, should be lauded rather than held against the Company.

Q. Dr. Zenger argues that the Aeolus-to-Bridger/Anticline line is an unnecessary "early acquisition" and that there is little downside risk to customers if the Combined Projects are not built. (Zenger Supplemental Rebuttal and Surrebuttal, lines 512–546, lines 591–592.) How do you respond to this claim?

A. I disagree. As Mr. Link explains in detail in his testimony, there is current need for resources and the Combined Projects are part of the least-cost, least-risk portfolio of resources needed to meet this need. While it is true that long-term transmission plans evolve as circumstances change over time, they remain the most important tool the Company has for determining the need for transmission resources, particularly because of the long lead time required for permitting and construction of major transmission facilities, as DPU has previously acknowledged. Since there is an immediate need for the Combined Projects, this is not an "early acquisition."

Dr. Zenger's casual dismissal of the current need for the Aeolus-to-Bridger/Anticline transmission line and the assertion that there is little downside risk to not moving forward with the Combined Projects does not consider that even a small change in generation resources or load will require the line to be built without the benefit of the federal production tax credits to offset the costs. This means that retail customers would bear the $697 million in costs with only revenue from third-party transmission customers as an offset. This is not an insubstantial or speculative risk. The Company has managed to postpone the construction of this transmission line by making incremental improvements to the system, but there are no other options at this point. I have no doubt that the Aeolus-to-Bridger/Anticline line will be built in the near future.

Not acting now to capture PTC benefits to offset the costs would be detrimental to customers.

Q. Mr. Peaco claims the fact that the Aeolus-to-Bridger/Anticline transmission line is included in the NTTG's recent regional study of transmission alternatives "does not provide any evidence that there is a need for the Transmission Projects independent of the Wind Projects." (Peaco Supplemental Rebuttal and Surrebuttal, lines 230–237.) Is Mr. Peaco correct?

A. No. NTTG concluded that the "NTTG area would be reliably served in the year 2026 only by including" several proposed transmission projects, including the Aeolus-to-Bridger Anticline line.[1] Contrary to Mr. Peaco's implication, the transmission line was not included in the study solely to accommodate PacifiCorp's plans for new wind generation. In the 2016-17 biennial study process, the NTTG transmission model did include high levels of wind resources in eastern Wyoming, but the size and location of the various resources were based on the needs of all of the load-serving entities and not based on the needs of a specific transmission project or a single load-serving entity. As part of the analysis, the NTTG Technical Work Group performed a critical review of each Energy Gateway sub-segment and included only required sub-segments in the 2016-17 NTTG Regional Transmission Plan.

Q. If the Company pursued solar projects instead of the Wind Projects, would the Aeolus-to-Bridger/Anticline transmission line still need to be built?

A. Yes, although the timing may be different. Based on current system conditions and

[1] NTTG 2016-2017 Regional Transmission Plan at 24 (Jan. 9, 2018) (available online at https://www.nttg.biz/site/index.php?option=com_docman&view=list&slug=2016-2017-regional-transmission-plan-final&Itemid=31).

demand for interconnection and transmission capacity in eastern Wyoming, the construction of the line will more likely than not be needed no later than 2024.

RISKS OF THE TRANSMISSION PROJECTS HAVE DECREASED

Cost Estimates

Q. Dr. Zenger asserts that the Company's cost estimates for the Combined Projects have been ever-evolving. (***See*** **Zenger Supplemental Rebuttal and Surrebuttal, lines 115–117.) Do you agree?**

A. No. The Company's cost estimate for the Aeolus-to-Bridger/Anticline transmission line has remained the same ($679.2 million) throughout this proceeding. (Vail Direct, page 12, Confidential Table 1). And the Company has confirmed through a competitive market solicitation that the cost estimate for the Aeolus-to-Bridger/Anticline transmission line is valid. Because the Aeolus-to-Bridger/Anticline line is 85 percent of the total cost of the Transmission Projects, cost certainty for that piece decreases the cost risk for the Transmission Projects as a whole.

The costs for the network upgrade piece of the Transmission Projects has changed as the results of the 2017R RFP have been finalized, as I described in my previous testimonies. (Vail Supplemental Direct and Rebuttal, lines 52–96; Vail Second Supplemental Direct, lines 27–44, 97–130.) But these changes are not surprising—the Company stated that the costs would be reassessed as the 2017R RFP process progresses. (Vail Direct, lines 290–293.)

Q. Dr. Zenger questions the Company's ability to accurately forecast the costs of the Transmission Projects, relying on an alleged discrepancy between the cost estimate for the Company's Populus-to-Terminal project and the actual costs. (Zenger Supplemental Rebuttal and Surrebuttal, lines 248–256.) Is Dr. Zenger's argument well-founded?

A. No. Dr. Zenger repeats the mistake made by Mr. Mullins in his direct testimony, (Mullins Direct, lines 11–15), and completely ignores my rebuttal testimony on this point. (Vail Supplemental Direct and Rebuttal, lines 571–595.) Both Dr. Zenger and Mr. Mullins identify $78 million as the Company's cost estimate for the Populus-to-Terminal project, but this is incorrect. As described in my rebuttal testimony, the $78 million relied upon by Dr. Zenger and Mr. Mullins was a high-level estimate of the cost to construct a 300-MW transmission line that was called for in one of the Company's 2006 merger commitments. The original cost estimate for the Populus-to-Terminal project was actually $750 million, which was within seven percent of the final project costs. In addition, the $750 million estimate was developed at an earlier stage of the process than the estimate for the Aeolus-to-Bridger/Anticline transmission line, so the Company has more data informing the estimate in this case (including a clear understanding of permit requirements, status, and progress, as well as the information from the competitive solicitation).

In addition, both Dr. Zenger and Mr. Mullins ignore my testimony on the Company's recent delivery of major transmission projects on time and on budget, namely the Mona-to-Oquirrh and the Sigurd-to-Red-Butte transmission lines. (Vail Supplemental Direct and Rebuttal, pages 24–25, lines 528–542.) Similarly, Mr. Hayet ignores this evidence in implying that PacifiCorp is relying on little more than "confidence" as evidence that it can deliver projects on time and on budget. (Hayet Second Rebuttal, lines 770–779.)

Q. Did Mr. Mullins address your rebuttal testimony regarding the Populus-to-Terminal project?

A. Yes, but Mr. Mullins inaccurately states that I "acknowledge[d] that the Populous [sic] to Terminal line was originally forecast to cost only $78 million, but ultimately cost $801 million" and dismisses my rebuttal on this point as a disagreement "with the relevance of that estimate." (Mullins Supplemental Rebuttal, lines 845–848.) This is a complete misstatement of my testimony. My rebuttal made it clear that the original estimate for the Populus-to-Terminal project was $750 million, not $78 million. (Vail Supplemental Direct and Rebuttal, lines 575–595.)

Mr. Mullins also claims that the Idaho Public Utilities Commission relied on the $78 million in disallowing a major portion of the Populus-to-Terminal line. (Mullins Supplemental Rebuttal Testimony, lines 848–850.) Mr. Mullins does not, however, provide a citation for this assertion, probably because he is wrongly describing the Idaho commission's order. The Idaho commission did not even reference the $78 million in its final order approving the Populus-to-Terminal transmission line. The Idaho commission did refer to the 300-MW line included in the merger commitment, but this was not relevant to the commission's decision regarding the Populus-to-Terminal line. Finally, the Idaho commission did not disallow recovery of any portion of the Populus-to-Terminal line. Instead, the Idaho commission bifurcated recovery of the line, allowing 73 percent of the investment in rates right away, and placing the remaining 27 percent in the account for plant held for future use. The Idaho commission explicitly explained: "This is not a disallowance requiring a write off but a deferral[.]" Case No. PAC-E-10-07, Order No. 32196 at 12 (Feb. 28, 2011).

Q. Mr. Mullins states that the Company is using "untested, undeveloped technology" rather than steel lattice transmission towers described in the Company's opening testimony, which could result in increased or unexpected costs. (Mullins Supplemental Rebuttal, lines 820–822.) Is Mr. Mullins correct?

A. No. The tower technology the Company proposes to use is neither "new" nor "undeveloped." The Company proposed steel lattice towers in direct testimony and continues to propose steel lattice towers—the only difference is that the Company changed to a "flat" configuration rather the previous "delta" configuration. Both configurations are commonly used in the transmission industry, but the advantage of the new configuration is that it will be shorter, lighter, and easier to build, which will reduce overall construction costs. Moreover, all of the new towers will be full-scaled tested to ensure that they meet or exceed the design loads before usage.

Q. Please summarize the progress of the tower design and development program.

A. The Company is making excellent progress towards completing the tower design and development program. As of May 1, 2018, all design work is complete for all six towers in the program. The primary tangent tower successfully completed full-load case testing in the last week of April 2018. This tower represents over 80 percent of all towers for the Aeolus-to-Bridger/Anticline line, providing certainty to the design and costs of the project for this item. Remaining tower-load case testing is scheduled for mid-May and early June 2018, with all tests complete by mid-June 2018.

Q. Mr. Mullins cites problems with the use of "new technologies," specifically relying on issues with NV Energy's "One Nevada Line." (Mullins Supplemental Rebuttal, lines 833–836.) Are the transmission towers proposed in this case comparable to those used on the One Nevada Line?

A. No. The One Nevada Line towers are constructed using long, slender, and smooth tubular members that, under specific wind conditions, can oscillate and result in severe structural damage. The phenomenon of wind-induced vortex shedding and harmonic oscillating motion (commonly referred as vortex-induced vibration) on long, slender structures is well understood and can be mitigated. Unlike the towers used for the One Nevada Line, the towers proposed to be used in this case are a common lattice type constructed of "L-shaped" angle members that have been successfully deployed worldwide. Also unlike the towers used for the One Nevada Line, lattice towers do not offer a single continuous and symmetrical smooth surface to support vortex shedding. Much like a guitar string, long, tubular poles may have one natural frequency enabling harmonic oscillation when subjected to wind of matching velocity. Lattice towers, which are comprised of irregular shapes in varying member lengths, will not have just one single composite frequency and are therefore naturally resistant to wind-induced harmonic resonance.

Q. Relying on the Company's response to UAE Data Request 5.4, Mr. Mullins claims that the ongoing capital maintenance and replacement costs for the Transmission Projects were not considered in the Company's economic analysis. (Mullins Supplemental Rebuttal, lines 485–487.) Is Mr. Mullins correct?

A. No. Mr. Mullins misstates the Company's response to UAE Data Request 5.4. He claims that the Company "states that is analyses did not consider the ongoing capital maintenance and replacements of the Transmission Projects." But what the response actually says is that ongoing capital additions or replacements are not expected, and ongoing operations and maintenance costs of $1 million per year in 2017 dollars are included in the economic analysis.

Q. Mr. Mullins claims that "ongoing capital cost of the transmission investment is significant in the study period." (*Id.*, lines 499–500.) Is he correct?

A. No. The Company currently operates and maintains 16,500 miles of transmission and over 1,000 substations, and has a number of preventative and corrective maintenance programs to extend the life of transmission assets. The addition of the transmission projects will not materially impact the overall capital maintenance budget for the system. The Company focuses on identifying efficiencies and prioritizes spend within the capital maintenance program and does not expect an increase to overall system costs associated with the new Transmission Projects.

Construction Schedule

Q. Mr. Peaco reiterates his concern that there is risk of losing PTCs if the Transmission Projects are not in service by December 31, 2020, claiming that PacifiCorp has changed its story about the importance of the timing of the Aeolus-to-Bridger/Anticline transmission line? (Peaco Supplemental Rebuttal and Surrebuttal, lines 39–42.) Do you agree?

A. No. The completion of the Aeolus-to-Bridger/Anticline transmission line has been and continues to be one of the key drivers of timing in this case. The Company did not change its position that completion of the line on time is important and is the

Company's "Plan A" to secure PTC eligibility and the full benefits of the Combined Projects.

In response to parties' concerns about PTC eligibility, the Company clarified that there is a "Plan B"—PTC eligibility can be secured if the Wind Projects are synchronized to the grid, which requires completion of the network upgrades identified in Exhibit RMP___(RAV-1SS). The Company should not be accused of changing position simply because it is responding to parties' arguments.

The network upgrades identified in Exhibit RMP___(RAV-1SS) are the types of transmission projects that the Company routinely builds in the ordinary course of business. The Company has extensive experience designing, constructing, and operating these types of facilities. The Company is confident that it can timely complete the projects necessary to secure PTC eligibility.

Q. Mr. Peaco claims that you did not clearly identify which facilities are needed to synchronize the Wind Projects to the grid. Did you provide this information?

A. Yes. The facilities that need to be in service for synchronization of the Wind Projects to the grid are identified in my Exhibit RMP____(RAV-1SS), although Mr. Peaco is correct that I did not explicitly identify these facilities as those necessary to synchronize the Wind Projects to the grid.

Q. Mr. Peaco states that customers would bear the risk of losing PTC benefits when wind production is curtailed for system-protection reasons (Peaco Supplemental Rebuttal and Surrebuttal, lines 334–336.) What is your response?

A. While Mr. Peaco is technically correct, he overstates the likelihood and the impact of this risk. Wind would only be curtailed under certain severe outage scenarios and, even then, only to generator-tripping amount required. The transmission system is designed to meet all NERC and Western Electricity Coordinating Council ("WECC") reliability and operating criteria for outage conditions. I also addressed this issue in my Supplemental Direct and Rebuttal testimony, lines 697–709.

Regulatory Approvals and Permits

Q. Dr. Zenger expresses concern that the Company has not obtained the necessary permits for the Aeolus-to-Bridger/Anticline line. (Zenger Rebuttal and Surrebuttal, page 5, lines 75–76). What is the current status of the permitting process?

A. The Company has made significant progress towards obtaining its remaining permits and authorizations, including:

- Receiving certificates of public convenience and necessity for the Transmission Projects (and the Wind Projects), conditioned on obtaining rights-of-way, from the Wyoming Public Service Commission, as discussed by Ms. Crane in her surrebuttal testimony.
- Receiving notice to proceed from the Bureau of Land Management ("BLM") for 30 percent of the Plan of Development appendices required for construction. One additional group (Group 2) of appendices have been through BLM review and are awaiting final approval letter from BLM. The final group of appendices (remaining 20 percent) will be submitted for review and approval on schedule after construction contractor selection and subsequent input to the remaining appendices.

- Submitting the Class III Cultural report to the BLM. This requirement is on track for completion in accordance with the project schedule.
- Receiving confirmation of the Aquatic Resources Inventory from the U.S. Army Corps of Engineers regarding acquisition of the required wetlands permits. This significant progress, in accordance with the project schedule, mitigates most of the project permitting risk.

PARTIES MISUNDERSTAND THE INTERCONNECTION STUDY AND RESTUDY PROCESSES

Q. Witnesses for DPU, OCS, and UAE/UIEC claim that the Company disqualified projects from the 2017R RFP based solely on interconnection queue position. (*See, e.g.*, Peterson Supplemental Rebuttal and Surrebuttal, lines 379–381 ("…the most significant failure of the RFP process was the last minute elimination of essentially all projects but the final short list projects due to the restudy by PacifiCorp transmission of the transmission interconnections."); Hayet Second Rebuttal, lines 726–730 ("…PacifiCorp determined bids had to be eliminated because those bids required completion of all Gateway West and South upgrades[.]")). Are they correct?

A. Absolutely not. As described in more detail by Mr. Link, the final shortlist of projects selected from the 2017R RFP was initially developed based on *economic analysis alone*. The interconnection restudy process was initiated and conducted completely independently from the 2017R RFP.

PacifiCorp transmission's restudies of the interconnection customers in the generation interconnection queue were initiated given the change in the in-service date of the Aeolus-to-Bridger/Anticline transmission line, which is a sub-segment of

Gateway West. Historically, the Company's interconnection studies did not include consideration of the components of its long-term transmission plan by sub-segment. Given the change in the expected in-service date from 2024 to 2020, PacifiCorp transmission initiated restudies to determine whether interconnection requirements changed based on this change.

Furthermore, only one of the resources selected to the final shortlist was eliminated after the interconnection restudy process—McFadden Ridge II, which was the Company's own bid. But the interconnection restudies revealed additional interconnection capacity, which allowed the selection of the more-economic Ekola Flats project, as described further by Mr. Link.

Contrary to some of the parties' assertions, and as discussed further by Mr. Link, the interconnection restudies did not result in "disqualification" of any of the RFP bidders. Before the restudies were conducted, the need for full build-out of the Gateway West and Gateway South projects to allow interconnection of additional wind resources was triggered at queue position Q708. Including the addition of the Aeolus-to-Bridger/Anticline transmission line in 2020 in the interconnection restudies created *additional* interconnection capacity. This means that, as a result of the restudies, *additional* projects became viable with the addition of the Aeolus-to-Bridger/Anticline line. After the restudies, the need for full build-out of Gateway West and Gateway South was triggered at queue position Q713. Those projects at Q713 and higher than that queue position were not viable without Gateway West and South both before and after the restudies.

Q. Mr. Peaco also contends that bidders were not aware of the interconnection constraints and would not have bid if they had been aware. (*See, e.g.*, Peterson Supplemental Rebuttal and Surrebuttal, lines 88–89.) Is this a reasonable argument?

A. No. The fact that full build-out of Gateway South was triggered at queue position Q708 before the restudies was publicly available because the interconnection studies for Q708 were publicly available on OASIS. The bidders to the RFP in lower queue positions knew or should have known that interconnection capacity was scarce. And in fact, the Company very publicly stated throughout multiple proceedings regarding the Combined Projects that no additional generators behind the TOT 4A constraint could interconnect today. This is one of the reasons the Company initially proposed including a requirement for completed system impact studies in the 2017R RFP—a requirement that was removed at the request of stakeholders and the independent evaluator in Utah. The lack of interconnection capability is and has been one of the primary drivers for the need for the new line, and this fact was well known.

Q. Mr. Mullins claims that the Company never disclosed its "position with respect to the interconnection queue" until January 31, 2018. (Mullins Supplemental Direct, lines 5–10.) Is this true?

A. No. Mr. Mullins implies that the Company's treatment of the interconnection queue was somehow novel or a change from prior practice, and therefore the Company should have provided earlier notice as part of the 2017R RFP. But there was nothing unusual about how the Company treated its interconnection queue or performed the restudies necessary to identify interconnection network upgrades. As described above, the

Company's treatment of the queue was consistent with long-standing FERC precedent and the clear terms of its OATT.

It is theoretically possible for PacifiCorp to file at FERC to change the required processing of its interconnection queue, but PacifiCorp transmission would still need to allocate interconnection capacity in sequential queue order. Changes to interconnection queue processing are generally used to address cost allocation among interconnection customers. But for facilities that are part of a utility's long-term transmission plan (like the Energy Gateway projects), the costs cannot be allocated to interconnection customers, so the method of conducting interconnection studies is irrelevant to the allocation of limited interconnection capacity to interconnection customers.

Q. Mr. Mullins further claims that he "was under the impression that all Wind RFP bids would be scored or evaluated on the same basis, with the Company being able to then either equalize or mitigate the bidding advantage otherwise available to a bidder with a higher queue position." (Mullins Supplemental Rebuttal, lines 283–286.) How do you respond?

A. First, the bids were evaluated and scored on the same basis, as described by Mr. Link. Second, the Company cannot "equalize" or "mitigate" the fact that some projects are higher in the interconnection queue than others. That would give preferential treatment to lower-queued projects, and such preferential treatment is prohibited by the terms of the Company's OATT.

Q. Mr. Hayet claims that the interconnection studies increased "transfer capability" from 1,270 MW to 1,510 MW. (Hayet Second Rebuttal, lines 227–229 and lines 252–254.) Is this correct?

A. No. Mr. Hayet is confusing *interconnection capacity* with *transfer capability*. The interconnection restudies resulted in an increase of interconnection capacity from 1,270 MW to 1,510 MW, meaning additional megawatts can *interconnect* to the transmission system. Although interconnection studies can include some deliverability analysis, interconnection studies are not used to determine *transfer capability* of a transmission line. Transfer capability is determined through transfer capability assessment studies. In this case, the transfer capability assessments show that transfer capability is increased by 951 MW with the addition of the Aeolus-to-Bridger/Anticline transmission line.

Mr. Mullins makes a similar error when he states that PacifiCorp's "position" is that it must reserve "transmission capacity" for each project in the interconnection queue. (Mullins Supplemental Rebuttal, lines 168–174.) In the interconnection study process, PacifiCorp must assume that every project higher in the interconnection queue has been interconnected, meaning we reserve *interconnection capacity* (not transmission capacity) for higher-queued projects, as required by FERC.

From my perspective as the vice president responsible for one of largest transmission systems in the western United States, this confusion over basic transmission concepts demonstrates these witnesses' lack of expertise on transmission issues.

THE PARTIES' CRITICISMS OF THE TRANSMISSION STUDIES ARE NOT WELL-FOUNDED OR ACCURATE

Q. Why have there been three different Aeolus West Transmission Path Transfer Capability Assessments?

A. The first version of the Aeolus West Transmission Path Transfer Capability Assessment (1.0 – October 2017; a copy of version 1.0 was provided with my supplemental direct and rebuttal testimony as Exhibit RMP___(RAV-4SD)) used resources in PacifiCorp's large generator interconnection queue as a proxy for new wind resources because the specific size and location of the new wind resources that would ultimately be selected through the 2017R RFP was not known at the time of the study. The Company selected projects for the assessment based on queue order and proximity to the proposed Aeolus substation, one terminus of the Aeolus-to-Bridger/Anticline line. The study indicated that the new Aeolus West path could achieve a transfer level of 1,696 MW and allow interconnection of up to 1,270 MW of new wind projects.

After this first report, the 2017R RFP shortlist was issued, which provided more information about the size and location of anticipated new wind projects. The Aeolus West Transmission Path Transfer Capability Assessment was therefore updated and version 2.0 (February 12, 2018) was developed (a copy of version 2.0 was provided to the parties through discovery). As updated, the assessment indicated that the new Aeolus West path could achieve a transfer level of 1,792 MW and allow interconnection of up to 1,510 MW of new wind generation.

When the change to the 2017R RFP shortlist was made, another updated Aeolus West Transmission Path Transfer Capability Assessment was performed, called version 2.1 and dated March 30, 2018. A copy of version 2.1 is attached as

Exhibit RMP___(RAV-2SR)[2]. Version 2.1 shows transfer levels of 1,829 MW and interconnection of up to 1510 MW of new wind generation.

Q. Mr. Peaco repeatedly emphasizes that the Aeolus West Transmission Path Transfer Capability Assessments are "preliminary." (*See, e.g.,* Peaco Supplemental Rebuttal and Surrebuttal, lines 64–65.) Does Mr. Peaco appear to understand the significance of this designation?

A. No. Mr. Peaco seems to believe that the preliminary nature of the assessment means that further studies are needed before the Company can determine whether the Wind Projects can be reliably interconnected. This is not correct, as discussed in more detail later in my testimony.

Q. What is the significance of the "preliminary" designation?

A. For the Aeolus West Transmission Path Transfer Capability Assessments, simultaneous interaction between the Aeolus West path and the TOT 4B path was evaluated; however, the interactions with other transmission paths (Yellowtail South, Jim Bridger West, TOT 1A and TOT 3) were monitored throughout the study. The interaction between the Aeolus West and the TOT 4B transmission paths is the most critical analysis that needs to be performed when evaluating facility additions necessary to support increasing transfers east to west across Wyoming. Because the interaction of the Aeolus West transmission path with TOT 3 (Path 36), Bonanza West (Path 33) and TOT 1A (Path 30) transmission paths was not studied, the three versions of the Aeolus West Transmission Path Transfer Capability Assessment is labeled "preliminary." Follow-on FAC-013-2 transfer capability assessments will be performed jointly with a

[2] The appendices to version 2.1 are voluminous and included in my workpapers.

Project Review Group made-up of affected parties (Idaho Power Company, Black Hills Power, Basin Electric, Western Area Power Administration, etc.). This process is not unusual and will not result in changes to the Aeolus-to-Bridger/Anticline transmission line.

Q. Mr. Peaco states that version 2.1 of the transfer capability study indicates that changes have been made to Aeolus-to-Bridger Anticline line that "will certainly add cost to the project." (**Peaco Supplemental Rebuttal and Surrebuttal, lines 1077–1079.) Is this true?**

A. No. Mr. Peaco identifies three "new" components: (1) an increase in the assumed size of the Aeolus 230-kV shunt reactor from 50 MVAr to 60 MVAr; (2) a new 60-MVAr shunt reactor added to Shirley Basin 230 kV; and (3) a change to the reconductoring of the Aeolus-to-Shirley-Basin 230-kV #1 and #2 lines. (Peaco Supplemental Rebuttal and Surrebuttal, lines 1048–1056.) The decrease in estimated costs for the Latham dynamic voltage controller help offset the cost of the change in size of the Aeolus shunt reactor and the addition of the Shirley Basin shunt reactor. The costs are still within the tolerance of the estimate for the project. The reconductoring change for the Aeolus-to-Shirley Basin 230-kV #1 line is included in the updated 230 kV network upgrade costs that are part of the revised analysis.

Q. Mr. Peaco also notes uncertainty regarding the dynamic voltage controller at Latham. (*Id.*, lines 1057–1062.) Has that uncertainty been resolved?

A. Yes. PacifiCorp's transmission planning team determined that Static Synchronous Condenser (STATCOM) technology is not required to provide dynamic voltage control at Lathan 230-kV substation. Instead, voltage control can be achieved by installing a

Static VAr Compensator (SVC) with an estimated size of +275/-60 MVAr. The size of this device is currently being evaluated by an outside consultant (Electranix) to verify system performance needs. To be clear, however, the Company's economic analysis conservatively assumed that it would require the highest cost dynamic support device at Latham; therefore, the additional studies will result in a decrease in project cost and a corresponding increase in customer benefits.

Q. Did the location of the final wind projects have an impact on the transfer capability achieved on the Aeolus West Transmission Path?

A. Yes. The location of the wind projects does result in the ability to achieve different levels of transfer capabilities across Aeolus West simultaneous with the TOT 4B path. It is not surprising that the locations of the projects were modified as the 2017R RFP processed progressed.

Q. Mr. Peaco claims that including the Uinta projects decreases stress on the Aeolus West path, thereby increasing transfer capability. (Peaco Supplemental Rebuttal and Surrebuttal, lines 1150–1152.) Is this accurate?

A. No. Due to the location of the Uinta projects in southwest Wyoming, these projects have no impact on the transfer capability of the Aeolus West path and did not contribute to increasing or decreasing the transfer capability achieved in the Aeolus West Transmission Path Transfer Capability Assessments.

Treatment of Interconnection Queue in Assessments

Q. Mr. Peaco claims that the Company's treatment of projects in the interconnection queue was "inconsistent" and implies that the inconsistencies were intentional and designed to increase transfer capability. (Peaco Supplemental Rebuttal and Surrebuttal, line 1096.) Is there any validity to these assertions?

A. No. Mr. Peaco bases his allegations on the mistaken belief that the interconnection agreements for the Ekola Flats (Q706), Bowler Flats (Q542), and Boswell (Q409) projects include similar requirements for the completion of Gateway West and Gateway South, and therefore there was no basis to remove Boswell from version 2.1 of the transfer assessment and include Ekola Flats and Bowler Flats.

Mr. Peaco is wrong. The LGIAs for Ekola Flats and Bowler Flats *do not require* the completion of Gateway West and Gateway South. The LGIA for Boswell explicitly does, and explicitly notes that these projects will not be in-service before 2024.

Q. Why was Boswell included in an earlier version of the transfer capability assessments if it has an executed LGIA requiring Gateway West and Gateway South?

A. As discussed above, the projects initially included in version 1.0 of the transfer capability assessment were proxies chosen based on queue position and proximity to the Aeolus substation. As the 2017R RFP process progressed, the Company no longer needed to include proxies in the assessment, so Boswell was removed.

Q. Bowler Flats is not one of the Wind Projects selected through the 2017R RFP, so why is it included in version 2.1 of the transfer capability assessment when none of the other non-selected generators in the interconnection queue were?

A. Version 2.1 of the transfer capability assessment includes Bowler Flats because that project has an executed LGIA that allows it to interconnect without the addition of the Aeolus-to-Bridger/Anticline line. Bowler Flats is the generator described above as the last generator that can interconnect today. To comply with this LGIA, the Company must reserve sufficient interconnection capacity for Bowler Flats.

Q. Mr. Peaco implies that the Company "updated" the interconnection agreement for Ekola Flats without restudying its interconnection. (Peaco Confidential Supplemental Rebuttal and Surrebuttal, lines 1137–1144.) How do you respond?

A. [redacted]

Q. Mr. Peaco states that the transfer capability assessment should include “all valid/active interconnection queue projects that would be in-service by the start of the study period.” (Peaco Confidential Supplemental Rebuttal and Surrebuttal, lines 1089–1092.) How do you respond?

A. The Aeolus West Transmission Path Transfer Capability Assessment study included those resources that will be in-service by the end of 2020, which includes those resources selected in the 2017R RFP. Because the focus of the transfer capability assessment study was to evaluate the increase in east-to-west transfers across Wyoming as a result of adding the Aeolus-to-Bridger/Anticline line, the specific focus was on addition of Wyoming generation resources. Other valid/active interconnection queue projects not included in the analysis were outside the scope of the project and will require additional transmission facilities to integrate. It makes no sense to include projects that cannot even “clamp on” to the system in a transfer capability assessment.

Use of Remedial Action Schemes in Assessments

Q. Mr. Peaco again criticizes the use of remedial action schemes (“RAS”) to increase transfer capability in the transfer capability assessment study. (Peaco Confidential Supplemental Rebuttal and Surrebuttal, lines 387–398.) Are Mr. Peaco’s criticisms valid?

A. No. The use of RAS is an accepted transmission planning tool. There is a formal process that is followed in the Western Interconnect for technical evaluation and approval by the Western Electricity Coordinating Council Remedial Action Scheme Review Subcommittee. All remedial action schemes must be vetted through this process before activation. The proposed Aeolus RAS will be subject to this same procedure.

Q. Would the planned implementation of the Aeolus West RAS scheme be considered an "excessive generator tripping" scheme as Mr. Peaco alleges? (Peaco Confidential Supplemental Rebuttal and Surrebuttal, lines 389–391.)

A. No. The planned Aeolus West RAS would not be considered excessive as it limits generator tripping to the single largest generator contingency (megawatt level) for the PacifiCorp East balancing authority area.

THE NEW WIND PROJECTS CAN BE RELIABLY INTERCONNECTED AND INTEGRATED

Q. Mr. Peaco appears to believe that additional studies are required to ensure "100 percent deliverability to network load." (Peaco Supplemental Rebuttal and Surrebuttal, lines 1155–1168.) Is he correct?

A. No. Mr. Peaco misunderstands the deliverability analysis conducted in the context of interconnection studies, and seems to confuse reliable interconnection with reliable integration. The system impact studies for the shortlisted projects demonstrate that the Wind Projects can be reliably interconnected. Mr. Peaco cites these studies to argue that "additional Energy Gateway projects and other system improvements would also be required" to ensure 100 percent deliverability of the project. Mr. Peaco is misunderstanding the deliverability information in the system impact studies, which is provided for informational purposes only and is non-binding. The focus of an interconnection study is *interconnection service*. While these studies include some information about deliverability, the information is preliminary, non-binding, and for informational purposes only. Full integration and deliverability requirements are determined when a customer requests *transmission service*.

Q. Do the Aeolus West Transfer Capability Assessments demonstrate full deliverability of the Wind Projects?

A. Yes. Study findings demonstrated that the output of all existing and new wind resources can be fully delivered by displacing Wyoming thermal generation with renewable generation. Mr. Peaco's concerns that there are no guarantees that the Company would be able to dispatch other resources to maintain 100 percent deliverability is belied by the assessments and is further discussed by Mr. Link.

The transfer capability assessments also confirm that the Wind Projects can be reliably interconnected. Version 2.1 of the assessment included detailed modeling of the Wind Projects, and both power flow and dynamic stability analysis was performed. This analysis demonstrated that with the Aeolus-to-Bridger/Anticline transmission line and the Wind Projects, system performance will meet all NERC and WECC performance criteria.

Q. Mr. Peaco notes that the March 30, 2018 Aeolus West Transmission Path Transfer Capability Assessment study report identified "poor" voltage performance and "unacceptable" oscillations for the Vestas wind turbines for specific wind farms identified on the wind project shortlist. (Peaco Supplemental Rebuttal and Surrebuttal, lines 1020–1026.) What is the current status of efforts to resolve the "unacceptable" oscillations identified for the Vestas wind turbine models?

A. Follow-on analysis has identified that the "poor" voltage performance and "unacceptable" oscillation for the Vestas wind turbines for specific wind farms identified on the wind project shortlist were due to a tuning problem with the power plant controller at specific wind farms. This problem has been corrected and a complete set of transmission system outages has been rerun to verify wind turbine performance. Additionally, the most recent transmission system model, including updates to the Vestas dynamic wind turbine models and parameters, has been forwarded to an outside consultant (Electranix) for more detailed Power System Computer Aided Design (PSCAD) modeling. The pre- and post-tuning correction plots are available upon request.

Q. Does this address Mr. Peaco's concern that changes to the wind turbines models could further modify the transfer capability and require revisions to system impact studies for the Wind Projects, potentially leading to increased costs? (***Id.*, lines 1027–1036.)**

A. Yes. The issue is resolved, so there is no risk of reduced transfer capability or modified interconnection requirements. I would also note that the system impact studies are *interconnection* studies. The outcome of the transfer capability assessments does not affect the findings in the interconnection studies. Moreover, as described by Mr. Link in his second supplemental direct testimony, the Company negotiated commercial terms that fully addressed the risk associated with the wind-turbine issue identified in the transfer capability assessment (Link Second Supplemental Direct, lines 497–532.)

OATT REVENUES

Q. Mr. Mullins and Mr. Peaco again question the Company's assumption that the Company will recover 12 percent of the revenue requirement of the Transmission Projects through its OATT rates. (Peaco Supplemental Rebuttal and Surrebuttal, lines 400–414; Mullins Supplemental Rebuttal, lines 598–670.) How do you respond?

A. The Company's estimate of third-party transmission revenues continues to be reasonable based on historical data and given the expected decline in PacifiCorp's load. As discussed in more detail below, transmission costs are allocated between transmission customers based primarily on load. If PacifiCorp's load decreases, its relative share of transmission costs also decreases. This makes the 12-percent assumption conservative rather than unreasonably high.

Q. Mr. Mullins claims that your "description of PacifiCorp's formula rate overlooks the way that costs get allocated between point-to-point and network integration transmission customers." (Mullins Supplemental Rebuttal, lines 625–626.) Do you agree with Mr. Mullins's argument?

A. No. Mr. Mullins's argument misunderstands how transmission rates are calculated. Mr. Mullins's argument assumes that the construction of the Wind Projects will increase the load served by network resources and therefore reduce the loads served by front-office transactions that rely on point-to-point transmission. He then speculates that this would increase PacifiCorp's network service load, but the Company would still have to pay for the same amount of point-to-point transmission service used to deliver front-office transactions.

Q. Is this a valid assumption?

A. No. Transmission costs are based on customers' relative share of load at the time of the transmission system peak plus long-term point-to-point capacity. Network transmission capacity is measured monthly at time of system peak. Therefore, over time, loads typically grow or shrink depending on many factors, including such items as population change, business mix, and the effects of weather. The addition of generation capacity by itself does not change a customer's load share of the transmission costs. PacifiCorp continually monitors and adjusts its transmission requirements, as do all other third-party customers. PacifiCorp's relative share of transmission costs are dependent on its load growth relative to third parties. Historically, allocation of PacifiCorp's use of transmission has been around 12 percent. Recent trends indicate that the Company's percent might be shrinking and the amount allocated to third parties increasing. Adding generation capacity is not expected to impact this trend. As a result, PacifiCorp's share of additional transmission costs would not be expected to increase relative to third parties based on constructing additional generation and transmission assets.

Q. Mr. Mullins claims that the cost of the Transmission Projects maybe directly assigned to PacifiCorp. (Mullins Supplemental Rebuttal, lines 646–649.) Is this a material risk?

A. No. Once again, Mr. Mullins appears to misunderstand how the Company's OATT formula rates are calculated. As mentioned above, PacifiCorp's transmission costs are recovered through a formula rate mechanism approved by FERC, so the risk of these costs being directly assigned is extremely low given how transmission costs are incorporated into the formula rate. Furthermore, under FERC policy and precedent, the costs of portions of a long-term transmission plan are not directly assignable to specific transmission customers, whether PacifiCorp's merchant function or third-party transmission customers.

Q. Mr. Mullins states that the Wind Projects will cause the Company's load to increase by about 450 megawatts per month, which will increase the Company's relative share of transmission costs. (Mullins Supplemental Rebuttal, lines 657–660.) Is this correct?

A. No. As noted above, the addition of generation resources does not necessarily mean that the Company will increase its share of the transmission usage. As previously described, transmission costs are allocated by demand during the transmission system peak. Mr. Mullins's own testimony therefore undermines his argument because he states that PacifiCorp's peak loads are forecasted to be down approximately 14 percent by 2026. (Mullins Supplemental Rebuttal, lines 783–784.) If peak loads are decreasing, as Mr. Mullins claims, then the Company's share of transmission costs will also decrease. Mr. Mullins cannot simultaneously argue that the new Wind Projects will increase transmission costs paid by retail customers while also arguing that load is decreasing, which has the practical effect of decreasing transmission costs paid by retail customers.

CONCLUSION

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Rick A. Vail

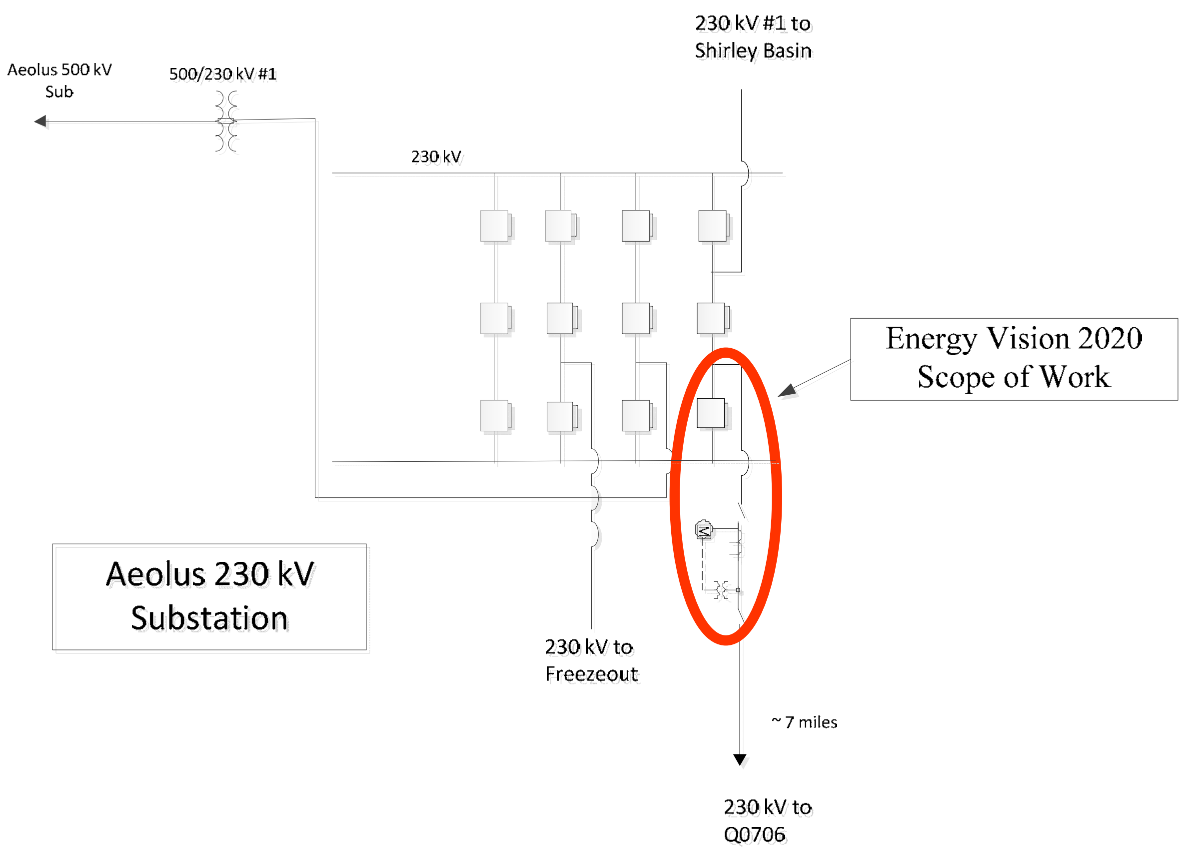
RFP Shortlist Network Upgrades

May 2018

May 7, 2018_v5

At the Aeolus Substation, to support the Ekola Flats Wind project the following network upgrades area required.

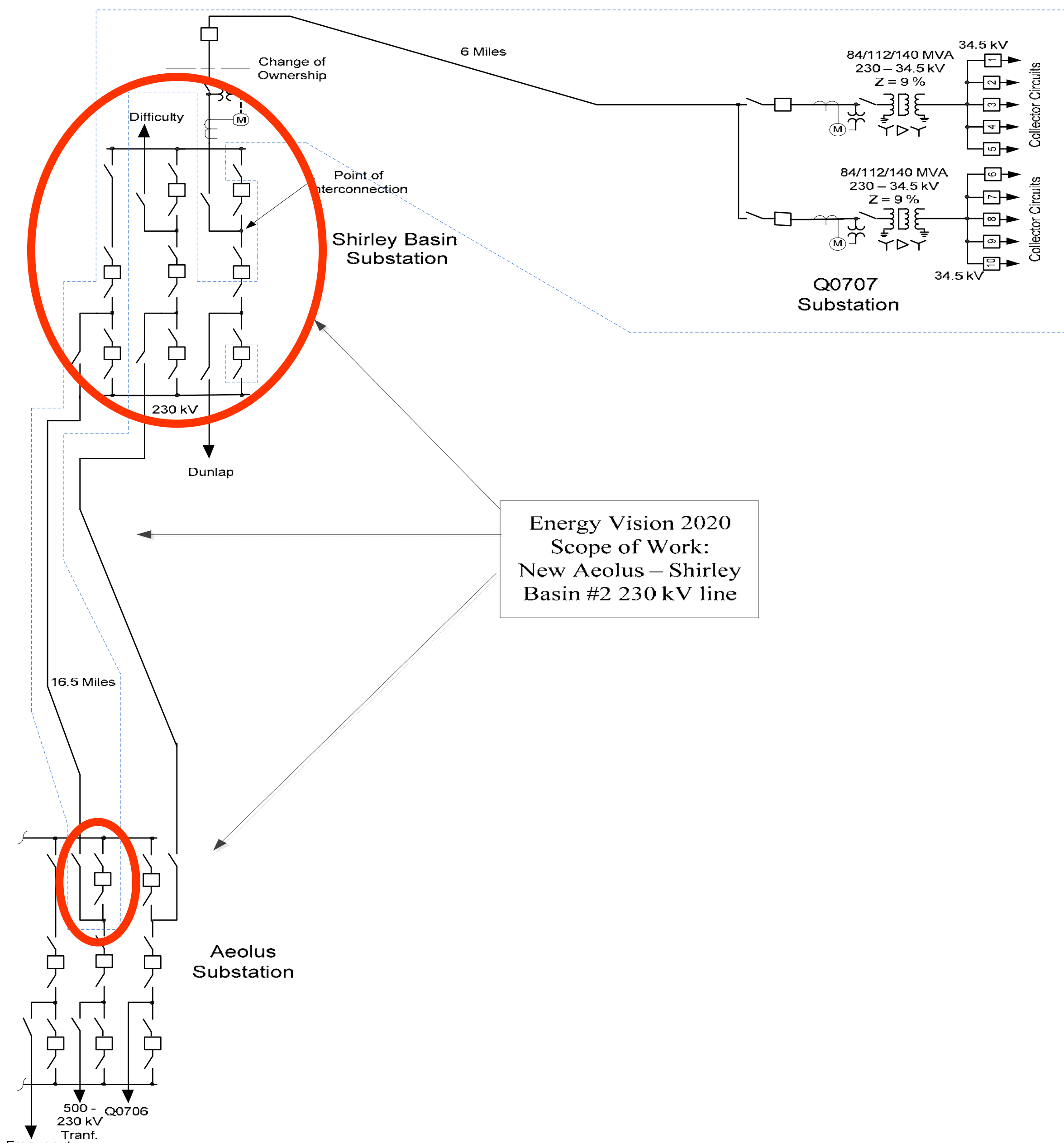
- One (1) 230 kV 3000 ampere breaker and line position with associated switches at Aeolus substation



At the Shirley Basin Substation, to support the inclusion of TB Flats I wind project the following network upgrades are required:

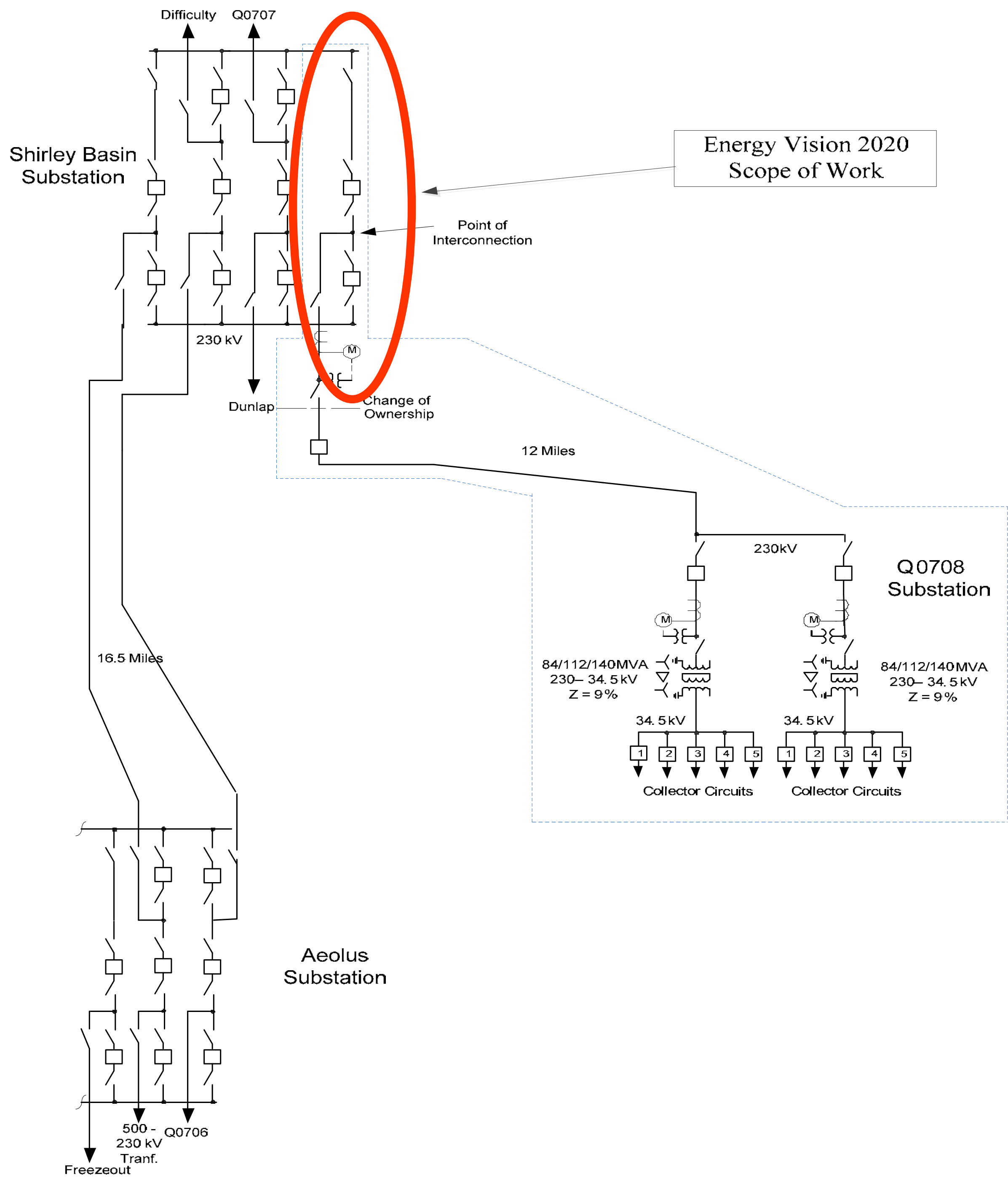
- A new bay, five (5) new 3000 ampere 230 kV breakers, two line terminations with associated switches
- Construction of a new approximately 16.5-mile Shirley Basin – Aeolus 230 kV #2 line

At the Aeolus substation the following network improvements are required:
- Addition of one (1) new 230 kV breaker, line termination and associated switches
- Inclusion of the project in the Aeolus RAS generation dropping scheme



At the Shirley Basin Substation, to support the inclusion of TB Flats II wind project the following network upgrades are required:

- Expansion of the Shirley Basin 230 kV switchyard on the east side of the substation with a new bay.
- Two (2) 230 kV 3000 ampere breakers, line termination and associated switches
- Inclusion of the project in the Aeolus RAS generation dropping scheme



At Windstar substation, to support the inclusion of Cedar Springs I wind project the following network upgrades are required:

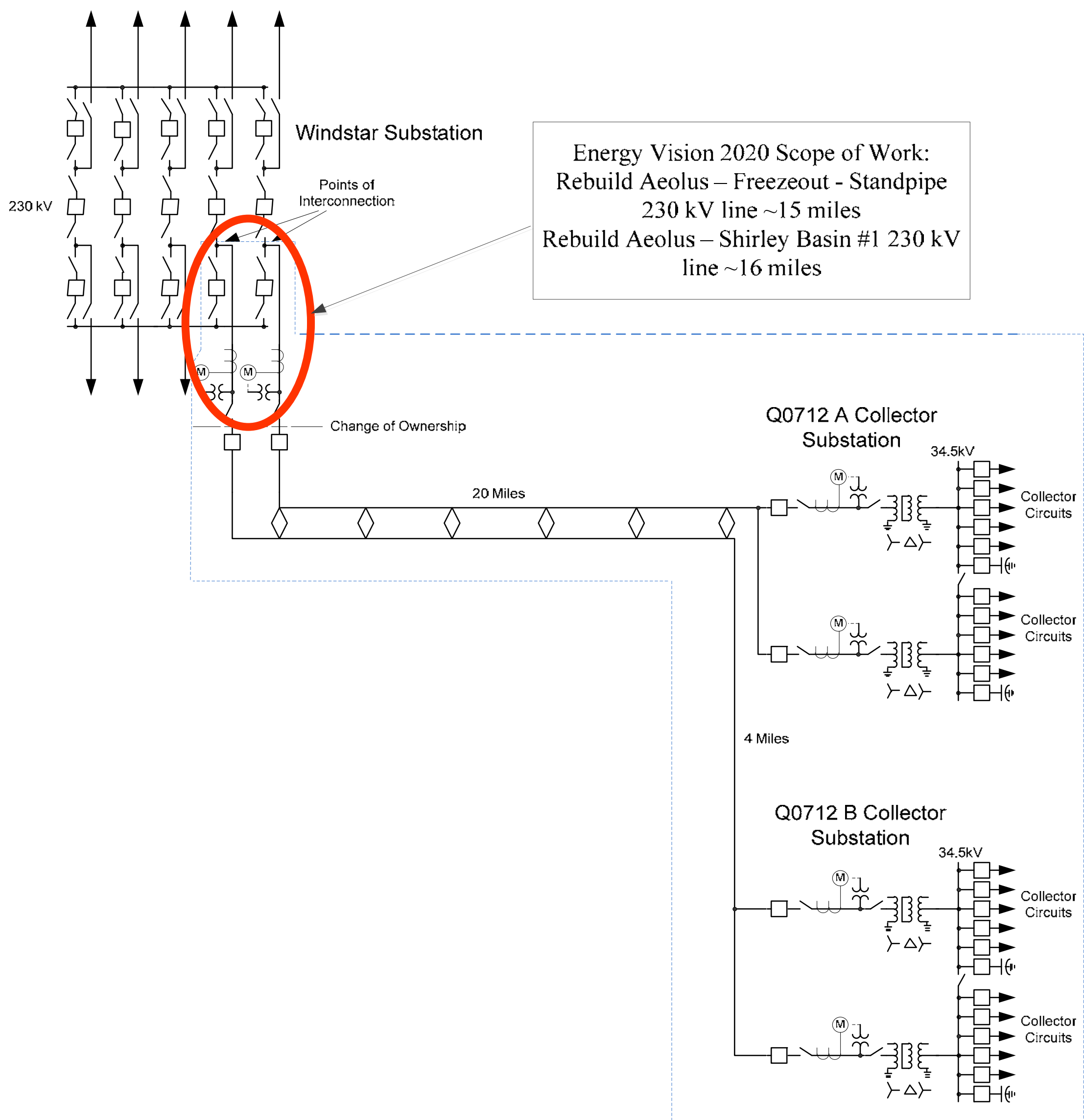
- Two (2) 230 kV 3000 ampere breakers and two line terminations with associated switches

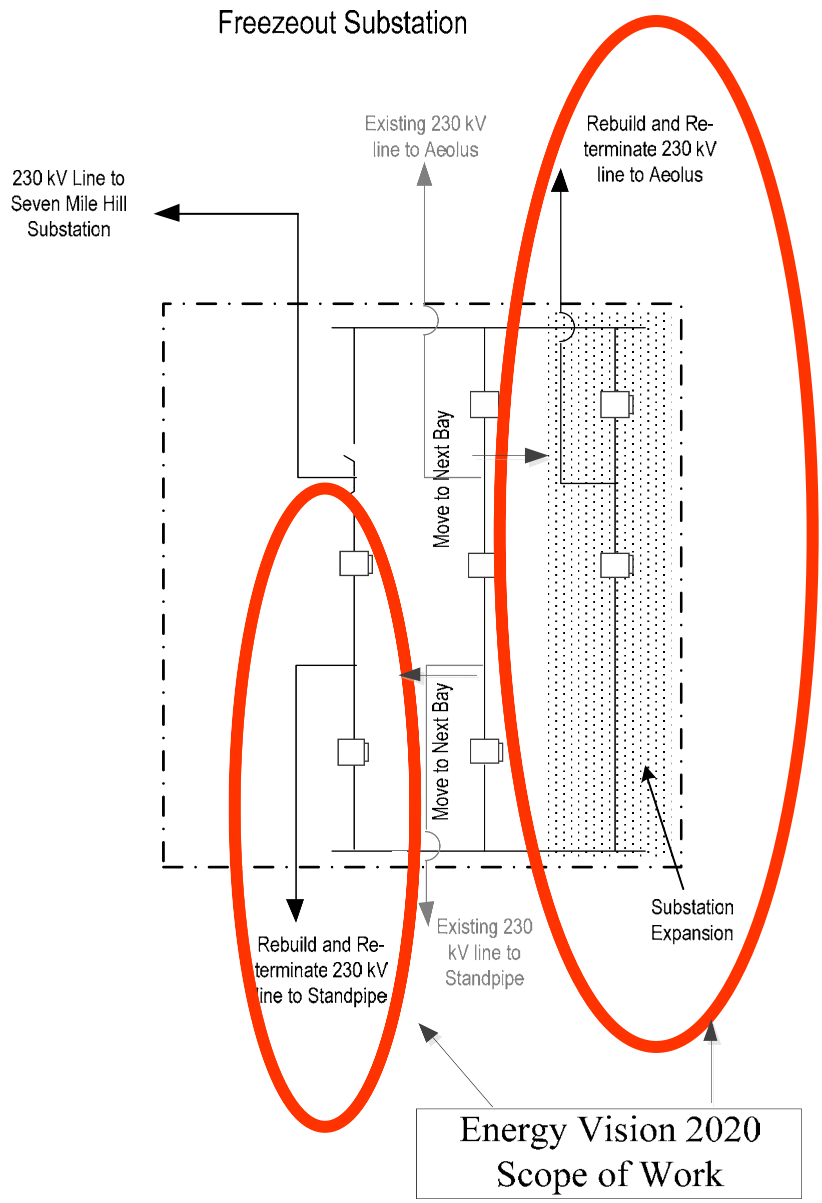
At Freezeout substation to support the inclusion of the Cedar Springs I wind project the following network upgrades are required:

- Add one new bay and four (4) 230 kV (3000 ampere) breakers along with associated switches (staged in two bays) for re-termination of lines associated with the Aeolus – Freezeout – Standpipe 230 kV line rebuild.

Rebuild the Aeolus – Freezeout – Standpipe 230 kV line ~ 15 miles

Rebuild the Shirley Basin - Aeolus 230 kV #1 line ~ 16 miles




Freezeout Substation
Existing 230 kV line to Aeolus
Rebuild and Re-terminate 230 kV line to Aeolus
230 kV Line to Seven Mile Hill Substation
Move to Next Bay
Move to Next Bay
Rebuild and Re-terminate 230 kV line to Standpipe
Existing 230 kV line to Standpipe
Substation Expansion
Energy Vision 2020 Scope of Work

D.2 Project Facilities:

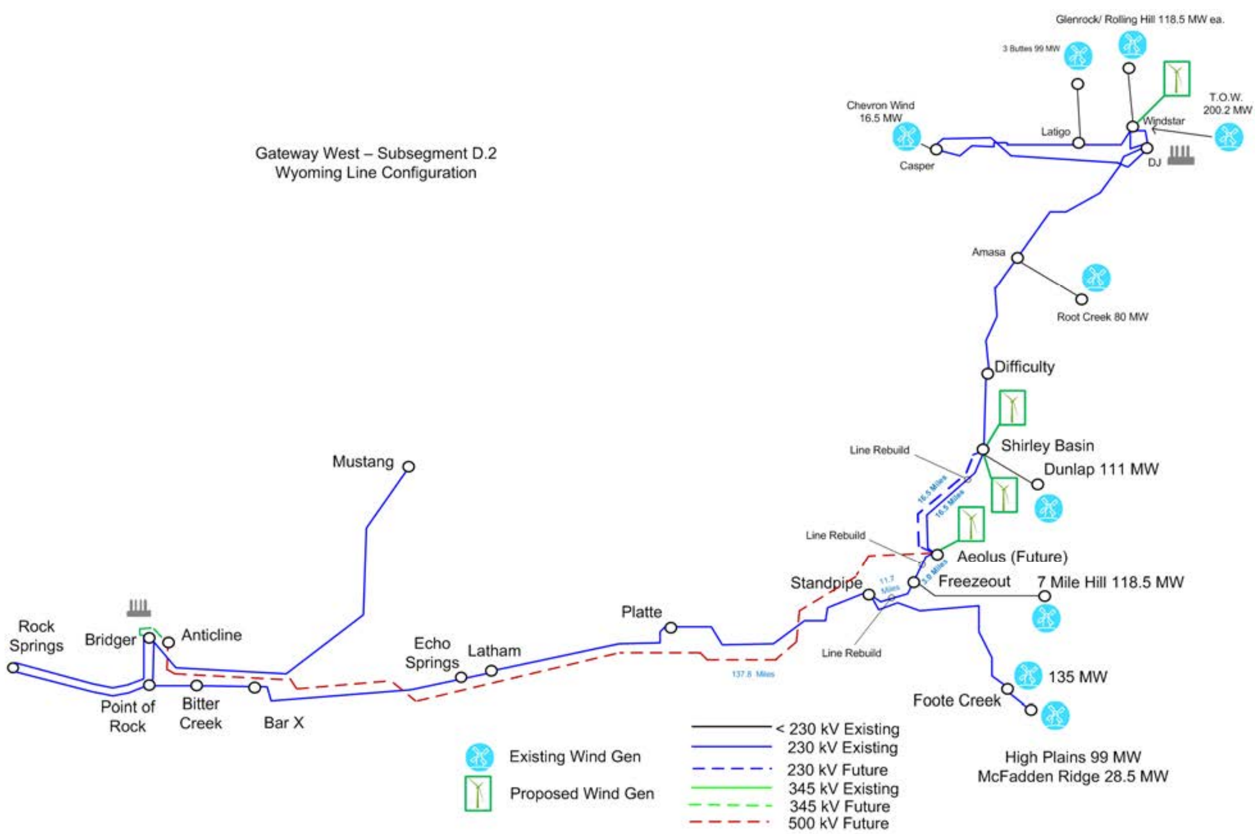
D.2 Project Transmission Facilities:

- Addition of the Aeolus 500/230 kV autotransformer
- Addition of the Aeolus – Anticline 500 kV line (~138 miles)
- Addition of the Anticline 500/345 kV autotransformer
- Addition of the Anticline – Bridger 345 kV line (5 miles)

Southeast Wyoming – Network Upgrades

- Loop the Shirley Basin – Freezeout 230 kV line into Aeolus 230 kV
- Add the Aeolus – Shirley Basin 230 kV #2 line (~16 miles) [Q0707]
- Rebuild the Aeolus – Shirley Basin 230 kV #1 line (~16 miles) [Q0712]
- Rebuild the Aeolus – Freezeout - Standpipe 230 kV line (~15 miles) [Q0712]
- Add Latham SVC

A drawing depicting all new D.2 Project network transmission facilities east of Jim Bridger Power Plant is provided below:



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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Rick A. Vail

Transfer Capability Assessment March 30, 2018

May 2018

Aeolus West Transmission Path Transfer Capability Assessment

Updated Study Report
Revision 2.1

March 30, 2018

Prepared by
PacifiCorp – Transmission Planning

Updated
Aeolus West Transmission Path
Transfer Capability Assessment

Table of Contents

Updated
Aeolus West Transmission Path
Transfer Capability Assessment

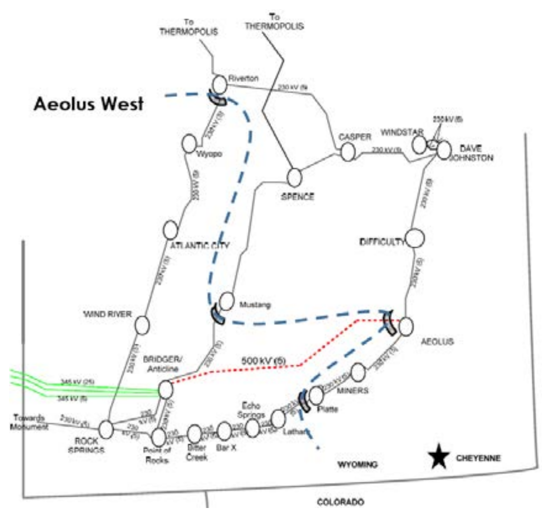
Executive Summary

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 and assumed resources identified in the PacifiCorp 2017R RFP[3] Shortlist were added.

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[4] (Path 37) transmission path facilities. The anticipated in-service date for the D.2 Project is October 31, 2020. The D.2 Project is part of PacifiCorp's Energy Vision 2020 (EV2020) initiative which includes the following major transmission facilities and network upgrades to support new wind generation resources:

- Aeolus 500/230 kV substation,
- Shirley Basin – Freezeout 230 kV line loop-in to Aeolus,
- Anticline 500/345 kV substation,
- Aeolus – Anticline 500 kV new line,
- Bridger – Anticline 345 kV new line,
- Shirley Basin – Aeolus 230 kV #1 line rebuild,
- Shirley Basin – Aeolus 230 kV #2 new line,

Figure 1: Aeolus West Transmission Path



[1] The Aeolus West transmission 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 the Aeolus West transmission path. [Subsequent to the initial announcement, technical studies have demonstrated that as high as 1,510 MW can be integrated east of the Aeolus West transmission path.]

[3] The PacifiCorp 2017R Request for Proposals for renewable resources (2017R RFP) solicited cost-competitive bids for up to 1,270 MW of new or repowered wind energy interconnecting with or delivering to PacifiCorp's Wyoming system with the use of third-party firm transmission service and any additional wind energy located outside of Wyoming capable of delivering energy to PacifiCorp's transmission system that will reduce system costs and provide net benefits for customers.

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

- Aeolus – Freezeout 230 kV line reconductor,
- Freezeout – Standpipe 230 kV line reconductor,
- Latham dynamic voltage control device,
- Separate the double-circuit portion of the Ben Lomond - Naughton 230 kV #1 and Ben Lomond - Birch Creek 230 kV #2 lines to create two single-circuit lines,
- Railroad – Croydon 138 kV partial line reconductor,
- Aeolus 230 kV shunt reactor,
- Shirley Basin 230 kV shunt reactor,

The WECC 2021-22 HW power flow base case was utilized for the Aeolus West transfer capability assessment 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 transfer levels evaluated by utilizing PacifiCorp 2017R RFP Shortlist resources as evaluated in the Large Generation Interconnection (LGI) queue, which added 1510 MW east of the Aeolus West "cut plane" and 221 MW in southwest Wyoming. For different Aeolus West transfer levels (heavy and light) and 2400 MW flow across the Jim Bridger West path, resource levels in eastern Wyoming were varied relative to the Jim Bridger Generation in central Wyoming and the Emery/Hunter and Huntington generation in central Utah.

Contingencies that were considered in this analysis include:

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

For this transfer capability assessment, simultaneous interaction between the Aeolus West path and the TOT 4B path was evaluated; however, the interactions with other transmission paths (Yellowtail South, Jim Bridger West, TOT 1A and TOT 3) were monitored throughout the study. Subsequent transfer capability assessments will evaluate interaction with TOT 3 (Path 36), Bonanza West (Path 33) and TOT 1A (Path 30) transmission paths. (See Appendix A.)

In this revision of the report, the power flow analysis was re-evaluated to identify maximum transfer capability by stressing both the Aeolus West and the TOT 4B paths simultaneously. If required, additional power from Western Area Power Administration (WAPA) was imported into the PacifiCorp East (PACE) balancing authority area.

Conclusions

Technical studies have demonstrated that the interconnected Bulk Electric System (BES) in Wyoming with the D.2 Project added can support the PacifiCorp 2017R RFP Shortlist resources, and that system performance will meet all North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) performance criteria.

Preliminary power flow studies demonstrate that by utilizing existing and planned southeast Wyoming resources[5], the Aeolus West transmission path can transfer up to 1829 MW under simultaneous transfer conditions with the TOT 4B transmission path, effectively[6] increasing the east to west transfer levels across Wyoming by 951 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, one Remedial Action Scheme (RAS) will need to be implemented to trip generation following outage of specific transmission facilities in southeast Wyoming.
- The location (and output level) of new and repowered wind resources can influence the transfer capability level across the Aeolus West transmission path and the Aeolus West vs. TOT 4B nomogram curve.

Dynamic stability studies evaluated a wide range of critical system disturbances in eastern Wyoming. The analyses identified two outages with poor voltage performance, and another outage identified a wind turbine modeling problem. These issues are all attributed to the wind turbine models at the Q0706, Q0707 and Q0708 projects. PacifiCorp is working with the wind turbine manufacture to resolve these issues. Aside from these issues, the studied outages evaluated meet the dynamic performance criteria with the system being stable and damped.

[5] Eastern Wyoming Resources: Existing Wind: 1124 MW, Dave Johnston (net) 717 MW; Wyodak (PacifiCorp – net) 268 MW, New Wind – behind the Aeolus West "cut plane": 1510 MW; east Wyoming: 1270 MW, north Wyoming: 240 MW.

[6] Effective transfers were determined by subtracting the existing TOT 4A path maximum[13] transfer level (960 MW) from the Aeolus West transfer level (1829 MW) and adding the Platte area loads (82 MW) that are up-stream of the Aeolus West metering point.

Updated
Aeolus West Transmission Path
Transfer Capability Assessment

1 Introduction

1.1 Purpose

The purpose of the study is to demonstrate that the interconnected transmission Bulk Electric System (BES) in Wyoming with the D.2 Project added can support the PacifiCorp 2017R RFP Shortlist resources and can be operated reliably during normal and contingency operations throughout the planning horizon. To achieve this purpose, the study will: (1) identify the new Aeolus West transmission path limitations, (2) evaluate the interactions between the Aeolus West and the TOT 4B transmission paths and develop a nomogram that depicts system limitations, and (3) identify any necessary Remedial Action Schemes (RAS).

This report will summarize the results of the power flow and dynamic stability analysis of the Aeolus West transmission path and will demonstrate that Wyoming transmission system performance with the D.2 project added meets all NERC and WECC performance criteria.

1.2 Plan of Service

The D.2 Project, and supporting network upgrades consists of the following system improvements:

1. Add Aeolus 500/230 kV substation
2. Add Aeolus 500/230 kV, 1600 MVA transformer
3. Loop the Shirley Basin – Freezeout 230 kV line into Aeolus,
4. Add Anticline 500/345 kV substation
5. Add Anticline 500/345 kV, 1600 MVA transformer
6. Add the Aeolus – Anticline 500 kV transmission line, 137.8-miles, 3x1272 ACSR (Bittern) conductor
7. Add the Anticline – Bridger 345 kV line, 5.1-miles, 3x1272 ACSR (Bittern) conductor
8. Add the Aeolus 230 kV, 60 MVAr shunt reactor
9. Add the Shirley Basin 230 kV, 60 MVAr shunt reactor
10. Add Aeolus 500 kV, 200 MVAr shunt capacitor
11. Add Anticline 500 kV, 200 MVAr shunt capacitor
12. Rebuilding of the Aeolus – Shirley Basin 230 kV #1 line, 2x1557 ACSS/TW (Hudson/TW) conductor
13. Add the Aeolus – Shirley Basin 230 kV #2 line, 2x1557 ACSS/TW (Hudson/TW) conductor
14. Reconductor the Aeolus – Freezeout 230 kV line, 2x1272 ACSR (Bittern) conductor

15. Reconductor the Freezeout – Standpipe 230 kV line, 2x1272 ACSR (Bittern) conductor
16. Add dynamic reactive device at Latham 230 kV substation.
17. Separate eight miles of the double-circuit Ben Lomond - Naughton 230 kV #1 and Ben Lomond - Birch Creek 230 kV #2 lines to create two single-circuit lines, and
18. Reconductor 2.35 miles of the Railroad - Croydon 138 kV line, 1222 ACCC high temperature conductor,

1.3 Planned Operating Date

The in-service date for all facilities associated with the D.2 Project is October 31, 2020.

1.4 Scope

The Aeolus West transfer capability assessment assumes the addition of new wind generation facilities as noted in Table 1, which includes the PacifiCorp 2017R RFP Shortlist resources as evaluated in LGI queue studies. While the new technology and model information of the repowered units was used in the steady-state and dynamic stability analysis, no incremental MW output was considered; i.e., each repowered facility was limited to its current LGI agreement generation capacity levels. The study was performed using a 2021-22 heavy winter WECC approved case which was modified to include the D.2 Project 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.

2 Study Criteria

2.1 Thermal Loading

For system normal conditions described by the P0[7] event, thermal loading on BES transmission lines and transformers is required to be within continuous ratings.

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

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

The thermal ratings of PacifiCorp's BES transmission lines and transformers are based on the most recent PacifiCorp's Weak Link Transmission Database and Weak Link Transformer Database.

Table 1: Generating Resources Studied

Existing Wyoming Thermal Generation	Existing East Wyoming Wind Generation	New Wyoming Wind Generation
2396 MW • Dave Johnston (DJ): 717 MW • Wyodak (PacifiCorp): 268 MW • Jim Bridger (PacifiCorp): 1411 MW	1124 MW (Foote Creek, Rock River, High Plains, Seven Mile Hill, Dunlap, Root Creek, Top of the World, Glenrock, Three Buttes, Chevron)	1731 MW • Eastern Wyoming (Aeolus, Shirley Basin, Windstar): 1270 MW • Northern Wyoming (Bighorn Basin): 240 MW • Southwest Wyoming (Uinta County) : 221 MW See Table 4.

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[8]" 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[9]	0.90	1.10
Radial	0.90	1.06[9]	0.85	1.10

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

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

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 Dynamic 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 dynamic voltage response shall be within established limits.

2.5 Dynamic Voltage Response

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

- Dynamic 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 planned transmission facilities (D.2 Project) and existing and new wind generation (see Table 1) facilities, and then tuning the cases to maximum transfer levels on the WECC transmission path(s) being studied. For this study, the WECC approved base case 2021-22 HW (created on August 19, 2016) was selected. This case meets key criteria in that it is close to the Projects’ in-service date of October 31, 2020, includes average load conditions based on 2021 load projections and has an accompanying dynamic stability base case available. 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 selected from the 2021-22 HW base case are listed below:

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

Load or Generation	**Amount (MW)**
North Wyoming PAC Load (including Wyodak load of 42 MW)	391 MW
North Wyoming - 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[10] in North Wyoming	26/50 MW(Online/Max)
WAPA's Existing Small Generation[11] 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)

[10] WAPA's small generation in north Wyoming includes; Boysen, Buffalo Bill, Heart Mountain, Shoshone, Spring Mountain

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

Load or Generation	**Amount (MW)**
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[12] 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 Flow	627 MW
TOT 4B Flow	469 MW
Jim Bridger (JB) Generation	2200 MW
Jim Bridger West Flow	2027 MW
TOT 3 Flow	1259.1 MW
TOT 1A Flow	195 MW
Platte – Mustang 115 kV Normal Open Point	Platte – Normal Open

3.2 Generating Facility Additions

The transmission path assessment studies outlined in Section 4 were performed by utilizing the resources identified in Table 4 to evaluate the performance of the Aeolus West transmission path. Transmission and generation projects with an in-service date beyond 2020 were excluded from the analysis. While Table 4 provides the general location of the resources included in the study, Figure 2 provides an overview of PacifiCorp's Wyoming transmission system and provides a visual illustration of the location of each of the existing and new generation (noted in red) resources, and identifies the location of the Aeolus West and TOT 4B transmission path constraints.

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

Table 4: New Wyoming Wind Resources

Proposed New Wind Facilities	LGI Queue Number	Project Size	Point of Interconnection
Northern Wyoming (Bighorn Basin)	Q542	240 MW	Frannie - Yellowtail 230 kV line
Eastern Wyoming (Aeolus/Shirley Basin/Windstar Area)	Q706	250 MW	Aeolus 230 kV
	Q707	250 MW	Shirley Basin 230 kV
	Q708	250 MW	Shirley Basin 230 kV
	Q712	520 MW	Windstar 230 kV
Southwest Wyoming (Uinta County)	Q715	120 MW	Canyon Compression – Railroad 138 kV line
	Q810	101 MW	Canyon Compression – Railroad 138 kV line
TOTAL		**1731 MW**	

3.3 Base Case Modification and Tuning

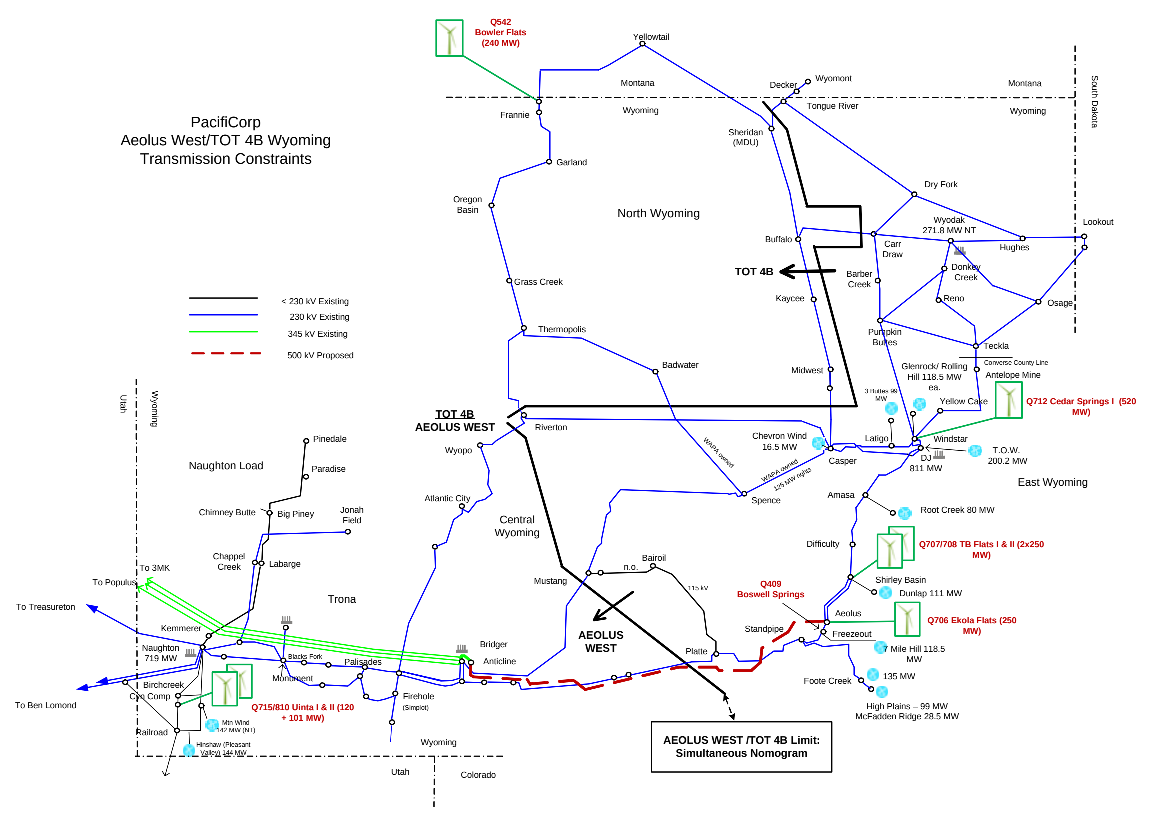
The 2021-22HW base case was modified to reflect the most recent Foote Creek, High Plains, Top of the World and Three Buttes wind generation modeling as per the recent MOD-032 data submitted by each generator owner (GO). Transmission line impedances between Dave Johnston and Standpipe were verified and 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 generation 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 capacity levels. The additional generation in southeast Wyoming was displaced with Jim Bridger, central and southern Utah generation. The Jim Bridger generation output was maintained such that Jim Bridger West path flows were maintained near 2400 MW.

As per the available data obtained for the 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

GSU loop flow conditions for wind generation facilities that have multiple main generator step-up GSU transformers.

Figure 2
Existing/Proposed Wyoming Generation Resources, and Transmission Constraints



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 1829 MW, while meeting all NERC and WECC performance criteria. While this transfer level is 869 MW above the present TOT 4A (960

MW[13]) path limit for similar conditions, east to west transfers have effectively increased by 951 MW due to shifting the Platte area load (82 MW) east of the Aeolus West cut plane. The Aeolus West path was stressed by using 3351 MW of total generation resources, which includes thermal (Dave Johnston, 717 MW - net), existing wind (1124 MW), and new wind (1510 MW) resources. The 240 MW of new wind resource in Big Horn Basin was varied with Wyodak generation as necessary. It was assumed that only the thermal generation at Dave Johnston and Wyodak generating plants in eastern Wyoming would be adjusted to maintain transfers on the Aeolus West and the TOT 4B transmission paths.

Table 5: Aeolus West and TOT 4B Corner Point Cases (See Figure 3)

Case	Aeolus West (MW)	TOT 4B (MW)	Limiting Element	Outage
1	1829	100	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
2	1803	300	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
3	1777	500	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
4	1763	607	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
			Dave Johnston South Tap – Refinery Tap – Casper 115 kV line	Casper 230 kV CB 1H4001 failure causing Casper – Dave Johnston 230 kV and Casper 230/115 kV transformer outage or Casper – Dave Johnston 230 kV line outage
5	1628	699	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS

[13] Maximum nomogram point with normal open point at Platte utilizing the dynamic line rating on Platte – Standpipe 230 kV line.

Case	Aeolus West (MW)	TOT 4B (MW)	Limiting Element	Outage
			Dave Johnston South Tap – Refinery Tap – Casper 115 kV line	Casper 230 kV CB 1H4001 failure causing Casper – Dave Johnston 230 kV and Casper 230/115 kV transformer outage or Casper – Dave Johnston 230 kV line outage
6	1125	880	Yellowtail – Sheridan 230 kV line	N-0

See Appendix B for power flow plots.

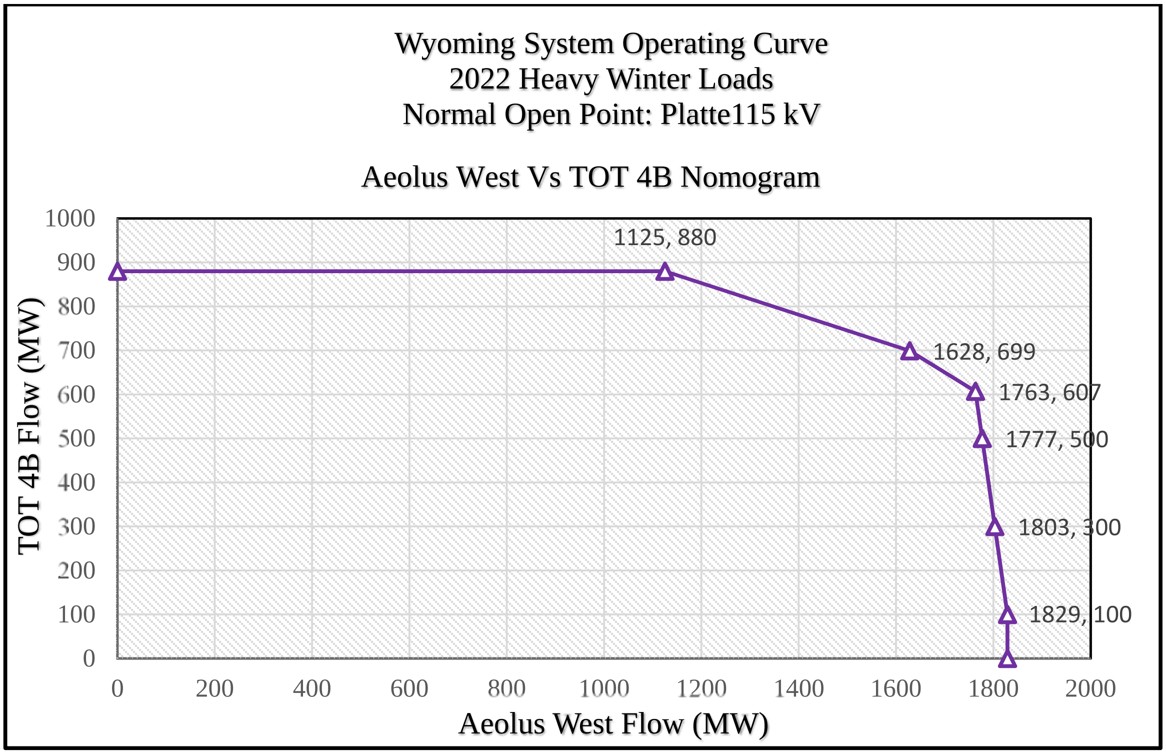
The low voltage issue in the Big Horn Wyoming area is an existing issue for the Yellowtail – Frannie 230 kV line outage or future Q0542 POI – Frannie 230 kV outage. This issue is resolved by adding capacitor banks at various locations in north Wyoming. A project to install a new 30 MVAr shunt capacitor bank at Grass Creek 230 kV, two new 20 MVAr shunt capacitor banks at Frannie and a new 7.5 MVAr capacitor bank at Hilltop 115 kV are proposed.

In the study, one RAS scheme was identified for N-1 outages:

i. Aeolus RAS to trip approximately 630 MW of wind generation depending on pre-outage flow conditions for any of the new transmission element outages between Aeolus – Jim Bridger.

Study results are summarized in Table 5 and illustrated in Figure 3. In reviewing Figure 3, it is evident that the Aeolus West and TOT 4B path interaction are minimized with the addition of the D.2 Project, as indicated by the straight horizontal line (implying no path interaction) when Aeolus West flows are below 1125 MW. The Aeolus West vs TOT 4B nomogram “knee point” is at Aeolus West flows of 1763 MW (TOT 4B, 607 MW). As TOT 4B flows increase from that point, Aeolus West flows reduce; likewise, from the knee point as TOT 4B flows decrease, Aeolus West flows increase.

Figure 3: Aeolus West Vs TOT 4B Nomogram



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 all of eastern and north Wyoming resources fora total of 3619 MW (existing and future) wind and net coal resources. These resources were displaced with Jim Bridger and resources in central and southern Utah such that the Jim Bridger West flows were maintained near 2400 MW.

The TOT 4B path flows were adjusted between a minimum of 100 MW and a maximum of 880 MW. Additional resources were exported from PACE to Montana and WAPA to Montana to adjust flows across the TOT 4B path between 300 MW and 880 MW using Crossover, Rimrock and Steam Plant phase shifting transformers in Montana.

The Shiprock, San Juan and Gladstone phase shifting transformers were locked to regulate flow across the TOT 3 path between Colorado and Wyoming.

4.3 Dynamic Stability Analysis

The dynamic stability analysis was performed using PSS/E models provided by both General Electric (GE) and Vestas's for the repowered and new wind generation. The generic model for the Root Creek wind model was updated to the GE0501 model (GE 1.85 units). Top of the World and Three Buttes wind farms in eastern Wyoming were updated to the GE 1.5 wind turbine model provided by GE for PTI V33. A generic WECC model was used for the Latham dynamic reactive device.

The stability study was focused in the eastern Wyoming region to demonstrate the acceptable performance from various new wind farms in the region. The real power, reactive power and voltage output from the new and the existing wind farm generators were reviewed to evaluate their ability to support the transmission grid voltage and system stability during various outage scenarios. Due to the combination of different wind turbine models, dynamic analysis also ensured that no interaction issues were being observed.

The dynamic stability study was performed for one (worst case) nomogram point on the Aeolus West vs. the TOT 4B nomogram curve, which reflected the heaviest Aeolus West flow conditions.

Dynamic stability analysis was performed on selective critical outages based on anticipated post fault impacts on the wind generation performance, especially for the portion of the system with a calculated short circuit ratio of approximately 2.3. See Appendix C for the dynamic stability analysis summary and dynamic plots.

5 Sensitivity Analysis

The sensitivity analysis focused on the evaluation of two different RAS generation tripping scenarios to ascertain which scheme would be the most effective at tripping generation following outage of the D.2 Project facilities between Bridger and Aeolus.

A dynamic stability sensitivity analysis was performed to evaluate the system impact and generator performance for a single element outage on the D.2 segment between Aeolus 230 kV and Bridger 345 kV buses which requires a RAS for generator tripping. Two different sets of generator tripping locations and tripping levels (approximately 630 MW) were selected. The generation tripping of 607 MW, which includes High Plains, Seven Mile Hill, Q706 and Dunlap wind generation was compared with generation tripping of 628 MW, which includes High Plains, Q0706 and Q0707 wind generation. For summary results and plots, please see dynamic simulation cases 1a – 1f2 in Appendix C.

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.

Updated power flow studies demonstrate that by utilizing existing and planned southeast Wyoming resources[5], the Aeolus West transmission path can transfer up to 1829 MW under simultaneous transfer conditions with the TOT 4B transmission path, effectively[6] increasing the east to west transfer levels across Wyoming by 951 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, one RAS scheme will need to be implemented to trip generation following the 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, the Aeolus West and TOT 4B nomogram curve and the area under the nomogram curve.

Dynamic stability studies evaluated a wide range of critical system disturbances in eastern Wyoming. The analyses identified two outages with poor voltage performance, and another outage identified a wind turbine modeling problem. These issues are all attributed to the wind turbine models at the Q0706, Q0707 and Q0708 projects. PacifiCorp is working with the wind turbine manufacture to resolve these issues. Aside from these issues, the studied outages evaluated meet the dynamic performance criteria with the system being stable and damped.

Report Appendices

Appendix A – Path Definitions

Appendix B – Power Flow Plots

Appendix C – Dynamic Stability Results (Case C7)

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
Surrebuttal Testimony of Rick T. Link

May 2018

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

A. Yes.

PURPOSE AND SUMMARY OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. My surrebuttal testimony further supports the company's voluntary request for approval of a resource decision for the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") and request for approval of the significant energy resource decision to acquire the Ekola Flats, TB Flats I and II, and Cedar Springs wind facilities ("Wind Projects" and, collectively, the "Combined Projects"). Specifically, my testimony responds to the April 17, 2018 testimonies filed by the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Mr. Charles E. Peterson and Mr. Daniel Peaco; Office of Consumer Services ("OCS") witness Mr. Philip Hayet; the Utah Association of Energy Users ("UAE") and the Utah Industrial Energy Consumers ("UIEC") witness Mr. Bradley G. Mullins; and the Western Resource Advocates ("WRA") witness Ms. Nancy L. Kelly.

Q. Please summarize your testimony.

A. First, I present the results of economic analysis with the removal of the Uinta project from the list of wind projects for which the company is seeking approval. Second, I respond to claims that PacifiCorp does not have a resource need. Third, I address criticisms of PacifiCorp's 2017R Request for Proposals ("2017R RFP"). Fourth, I rebut criticisms of the company's economic analysis, which shows that the Combined Projects will generate significant customer benefits. Fifth, I address process criticisms.

Sixth, I address project risks. Finally, in response to claims that the Combined Projects may not be the least-cost, least-risk resource option, I summarize the economic analysis used to finalize PacifiCorp's 2017S Request for Proposals ("2017S RFP") bid-selection process.

My surrebuttal testimony demonstrates:

- The removal of the Uinta project does not negatively affect the economics of the Combined Projects. The Combined Projects (without Uinta) show benefits of $174 million in the medium case through 2050, and benefits of $338 million in the medium case through 2036. In the 18 scenarios studied (nine each for the 2050 and 2036 analyses), 16 of 18 cases show net customer benefits.

- Even after accounting for the updated load forecast that is summarized in my supplemental direct testimony, PacifiCorp has a 595-MW capacity deficit in 2021 that grows to 3,395 MW in 2036, and the Combined Projects are part of the least-cost, least-risk resource portfolio to meet this need.

- As supported by independent evaluators that were appointed and managed by two different state regulatory commissions, the 2017R RFP was fair, transparent, and unbiased.

- These independent evaluators found that the bids selected to the 2017R RFP final shortlist represent the top offers that are viable under current transmission planning assumptions, and the Utah independent evaluator, concluded that the final shortlist should result in significant savings for customers.

- The company has performed over 1,300 20-year simulations of PacifiCorp's system to thoroughly evaluate how the net benefits of the Combined Projects are affected by a broad range of variables and uncertainties. The economic analyses are robust, demonstrating that the Combined Projects are in the public interest and "most likely to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to customers." In fact, even though the company disagrees that a higher standard of review somehow applies in this case, the economic analyses demonstrate that the Combined Projects meet even this higher standard, with net customer benefits in 16 out of the 18 cases (meaning the Combined Projects have a high likelihood of providing benefits to customers).

- While solar resources may provide customer benefits, contrary to claims from certain parties, solar resource bids submitted into the 2017S RFP are not a superior resource alternative to the Combined Projects.

- The Company's 2036 integrated resource plan ("IRP") analysis shows that the Combined Projects are a lower cost resource than the solar resources in the medium case, even before considering the solar risk sensitivities. In the 2050 nominal revenue requirement analysis, the Combined Projects and the solar resources produce comparable net benefits in the medium case after accounting for the solar risk sensitivities. Moreover, if the construction of the Aeolus-to-Bridger/Anticline transmission line is included in the base case modeling in the 2050 analysis—consistent with the Company's and region's current long-term transmission plan—then the net benefits of the Combined Projects would be nearly $300 million higher than the solar resources in all cases.

- Solar resources are best viewed as an incremental opportunity, not as an alternative to the Combined Projects.

- During the evaluation of bids in the 2017S RFP, PacifiCorp analyzed valuation risks that are unique to the procurement of solar resources and determined that solar resource costs are likely to continue to fall.

- Given these solar resource-valuation risks, expected cost declines, and availability of the 30-percent investment tax credit ("ITC") for solar projects coming online as late as 2021, PacifiCorp does not need to act now and has decided not to select any of the solar power-purchase agreement ("PPA") bids to the 2017S RFP final shortlist.

- PacifiCorp will continue to assess potential economic benefits from solar-resource opportunities through bi-lateral opportunities and in the 2019 IRP, including a thorough review of valuation risks with full stakeholder engagement, to determine whether a new competitive solicitation process for projects capable of achieving commercial operation by the end of 2021 will provide customer benefits.

- In contrast, the phase-out of production tax credit ("PTC") benefits that are available for qualifying wind projects occurs sooner than the ramp down of ITC benefits that are available for solar resources, which requires that PacifiCorp act now to deliver the new wind and needed transmission investments that will produce both near-term and long-term benefits for customers.

REMOVAL OF UINTA

Q. Ms. Cindy A. Crane states that the company removed Uinta from the wind projects for which the company is seeking approval to respond to parties' concerns and to align the request in this docket with the stipulations in Wyoming and Idaho. Please summarize the cost-and-performance attributes of the wind projects without Uinta.

A. With removal of the Uinta project, the total in-service capital cost for the remaining wind projects is approximately $[redacted] billion. Relative to the company's initial filing, the per-unit capital cost of the stipulated wind projects is down [redacted] percent from $1,590/kW to $[redacted]/kW. The power-purchase agreement pricing for 50 percent of the output of the Cedar Springs project is unchanged from what was described in my second supplemental direct testimony. And in aggregate, the Wind Projects are expected to operate at a capacity-weighted average annual capacity factor of [redacted] percent.

Q. What is the nominal value of PTCs relative to the in-service capital cost of the stipulated wind projects?

A. Over the first ten years of operation, the stipulated wind projects that will be owned by PacifiCorp will generate over $1.2 billion in PTC benefits, which is nearly 103 percent of the in-service capital for these wind facilities.

Q. Has the company updated the economic analysis of the Combined Projects based on the removal of the Uinta project?

A. Yes. First, I performed a spreadsheet analysis to estimate the high-level economic impact of removing the Uinta project. I performed this spreadsheet analysis for all nine price-policy scenarios previously described in my testimony. Consistent with the company's prior economic analysis, I provide these results based on the methodology used in the company's IRP through 2036 and using nominal revenue requirement projections through 2050.

Q. Please describe how you performed the high-level spreadsheet analysis.

A. Using data from the economic analysis presented in my supplemental direct and rebuttal testimony, I calculated the system benefits, including the Uinta Project, on a dollar-per-MWh basis for each price-policy scenario. I then multiplied these results by the expected generation from the Uinta project to estimate the annual system benefits associated with the Uinta project in total dollars. These system-benefit estimates were then netted against the same project-specific costs for the Uinta facility that were used in the economic analysis summarized in my second supplemental direct testimony. This calculation results in an estimate of the marginal net benefit or cost of removing the Uinta project for each price-policy scenario.

Q. Did you also update the economic analysis using the company's models?

A. Yes. I also re-ran the company's IRP models to remove Uinta under the medium natural gas, medium carbon dioxide ("CO_2") and low natural gas, zero CO_2 price-policy scenarios.

Q. Did you update any of the other inputs used in the analysis?

A. No. Other than removing Uinta, all the other inputs used in the economic analysis are the same as the inputs used in the company's second supplemental direct testimony filed on February 16, 2018.

Q. What is the high-level estimate of the economic impact of removing Uinta based on results through 2036?

A. Table 1-SR reports the high-level estimate of the economic impact of removing Uinta based on the results through 2036. These present-value revenue-requirement differential ("PVRR(d)") results are shown alongside the results summarized in my supplemental direct and rebuttal testimony. The difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 1-SR: Estimated Impact of Removing Uinta
PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036

Price-Policy Scenario	Second Supplemental Direct Filing (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	($150)	($146)	($4)
Low Gas, Medium CO_2	($179)	($172)	($7)
Low Gas, High CO_2	($337)	($312)	($25)
Medium Gas, Zero CO_2	($319)	($296)	($23)
Medium Gas, Medium CO_2	($357)	($330)	($27)
Medium Gas, High CO_2	($448)	($410)	($38)
High Gas, Zero CO_2	($568)	($517)	($51)
High Gas, Medium CO_2	($603)	($548)	($55)
High Gas, High CO_2	($694)	($629)	($66)

Q. What conclusions can you draw from the results provided in Table 1-SR?

A. The high-level estimate based on results through 2036 shows that net benefits of the Combined Projects (without Uinta) are reduced by between $4 million and $66 million. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $27 million. Considering that results from the IRP models were used to select winning bids in the 2017R RFP, these findings confirm that it was reasonable to include Uinta in the 2017R RFP final shortlist, and that there could still be an opportunity to pursue this project to deliver customer benefits outside of this proceeding. Importantly, these results also show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects range between $146 million and $629 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $330 million.

Q. What is the high-level estimate of the economic impact of removing Uinta based on nominal revenue requirement results through 2050?

A. Table 2-SR reports the high-level estimate of the economic impact of removing Uinta based on the nominal revenue requirement results through 2050. These PVRR(d) results are shown alongside the results summarized in my second supplemental direct testimony. Like Table 1-SR above, the difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 2-SR: Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

Price-Policy Scenario	Second Supplemental Direct Filing (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	$184	$146	$38
Low Gas, Medium CO_2	$127	$97	$31
Low Gas, High CO_2	($147)	($145)	($2)
Medium Gas, Zero CO_2	($92)	($97)	$5
Medium Gas, Medium CO_2	($167)	($162)	($4)
Medium Gas, High CO_2	($304)	($283)	($20)
High Gas, Zero CO_2	($448)	($411)	($37)
High Gas, Medium CO_2	($499)	($456)	($43)
High Gas, High CO_2	($635)	($576)	($59)

Q. What conclusions can you draw from Table 2-SR?

A. The high-level estimate based on nominal revenue requirement results through 2050 shows that removal of Uinta reduces the net cost of the Combined Projects in three of the nine price-policy scenarios, and that the net benefits of the Combined Projects are reduced in six of the nine price-policy scenarios. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $4 million. Importantly, when the impact of net benefits are based on nominal revenue requirement results through 2050, these results show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects in the scenarios where they occur range between $97 million and $576 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $162 million.

Q. In a previous request for approval of a resource decision by the company, DPU used the simple average of the price-policy scenarios as a "risk-weighted benefit" that assumes each of the price-policy results is "equally likely." What is the risk-weighted benefit in this case?

A. Under the 2036 IRP modeling, the scenarios produce a risk-weighted net benefit of \$373 million. Under the 2050 nominal modeling, the scenarios produce a risk-weighted net benefit of \$210 million. *See In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4,* Docket No. 12-035-92, DPU Exhibit 2.0 SR, lines 52–58 (Feb. 28, 2013).

Q. What is the economic impact of removing Uinta based on updated results from the IRP model runs?

A. Table 3-SR reports the high-level estimate of the economic impact of removing Uinta alongside the updated modeled results using the 2036 and 2050 calculation methodologies. These results are presented for both the low natural gas, zero CO_2 and the medium natural gas, medium CO_2 price-policy scenarios. The table also shows the difference between the high-level estimate and the modeled results.

Table 3-SR: Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036			
Price-Policy Scenario	**High-Level Estimate (Without Uinta)**	**Modeled Result (Without Uinta)**	**Variance from Modeled Result**
Low Gas, Zero CO_2	($146)	($143)	($3)
Medium Gas, Medium CO_2	($330)	($338)	$8
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050			
Price-Policy Scenario	**High-Level Estimate (Without Uinta)**	**Modeled Result (Without Uinta)**	**Variance from Modeled Result**
Low Gas, Zero CO_2	$146	$154	($8)
Medium Gas, Medium CO_2	($162)	($174)	$12

Q. What conclusions can you draw from Table 3-SR?

A. First, the modeled results are similar to the high-level estimates described above, and consequently, the high-level estimates provide a reasonable representation of the impact of removing Uinta.

Second, under the medium natural gas, medium CO_2 price-policy scenario, the Combined Projects still provide net customer benefits when Uinta is removed. When calculated from IRP model results through 2036, customer net benefits are $338 million (down by $19 million from $357 million that was reported in my second supplemental testimony). When calculated from the nominal revenue requirement results through 2050, customer net benefits are $174 million (up by $7 million from the $167 million that was reported in my second supplemental direct testimony).

Third, under the low natural gas, zero CO_2 price-policy scenario, the Combined Projects still provide net customer benefits with Uinta removed when the PVRR(d) is calculated from IRP model results through 2036. Based on this methodology, customer net benefits are $143 million (down by $7 million from the $150 million benefit that was reported in my supplemental direct and rebuttal testimony). When calculated from the nominal revenue requirement results through 2050, net costs are $154 million (down by $30 million from the $184 million that was reported in my supplemental direct and rebuttal testimony).

Q. Have you calculated the change in capital costs that would have to occur to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario?

A. Yes. Removal of the Uinta project reduces capital costs for the Combined Projects to $[redacted] billion, as outlined by Ms. Joelle Steward. In-service capital costs would have to increase by approximately 11.1 percent (or $[redacted] million) to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario.

Q. Do the Combined Projects without Uinta still provide overall customer net benefits?

A. Yes. As set forth above, when using the IRP modeling, the Combined Projects still provide robust customer net benefits under all nine price-policy scenarios. Although the benefits have decreased slightly, they remain substantial. In addition, under the nominal revenue requirement view, the net benefits remained fairly consistent, increasing in some price-policy scenarios and decreasing in others. Although neither view is dispositive, each of these views provides important insight into how the Combined Projects are expected to impact the company's revenue requirement. Taken together, each of these views indicate that the removal of Uinta does not adversely impact the customer benefits, and the acquisition of the Combined Projects remains in the public interest.

Q. Does the removal of Uinta address the concerns raised by Mr. Peaco? (Peaco Supplemental Rebuttal and Surrebuttal, lines 673–736.)

A. Yes.

THE COMBINED PROJECTS ARE NEEDED TODAY

Q. Dr. Zenger and Messrs. Peaco, Hayet and Mullins continue to question the need for the Combined Projects. (Zenger Supplemental Rebuttal and Surrebuttal, lines 500–504; Peaco Supplemental Rebuttal and Surrebuttal, lines 365–367; Hayet Second Rebuttal, lines 127–135; Mullins Supplemental Rebuttal, lines 758–763.) Are these witnesses correct that there is no resource need now or in the next 10 years?

A. Absolutely not. In my rebuttal testimony, I explained in detail that PacifiCorp has an immediate resource need and that the Combined Projects displace higher-cost, higher-risk front-office transactions ("FOTs") in the near term and defer the need for other higher-cost resources in the 2028 timeframe. (Link Supplemental Direct and Rebuttal, lines 772-897.) Therefore the Combined Projects meet both near-term resource need and a long-term resource need as identified in the 2017 IRP.

Q. Mr. Mullins claims that the company's position on resource need is imprudent because it "disregards market access" when determining resource sufficiency. (Mullins Supplemental Rebuttal, lines 767–770.) Similarly, Dr. Zenger asserts that the Combined Projects do not meet an identified deficiency. (Zenger Supplemental Rebuttal and Surrebuttal, lines 500–502.) Do you agree?

A. No. In their interpretation of PacifiCorp's capacity position, Mr. Mullins and Dr. Zenger are effectively treating uncommitted FOT resources as existing resources that should be applied as a reduction to the company's projected capacity shortfall. This is contrary to basic least-cost planning principals, and more importantly, contrary to the IRP standards and guidelines adopted by the Utah Public Service Commission ("Utah Commission") in Docket No. 90-2035-01. Specifically, their positions are contrary to Guideline 4.b, which states that IRPs are to include: "An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis."

Mr. Mullins's and Dr. Zenger's position would require that PacifiCorp assess its resource need assuming that uncommitted FOT resources will always be available and that these resources should be used to offset a capacity shortfall regardless of cost. This would be an imprudent course of action. The real issue is not whether PacifiCorp has a resource need—it does—but whether the Combined Projects are lower cost and lower risk relative to other resource alternatives. PacifiCorp does not ignore FOTs in its IRP modeling, which is the exact same modeling used in this case. In fact, as I have described in previous testimony, FOTs must compete against all other resource options, including the Combined Projects, which is consistent with the Commission's IRP standards and guidelines.

Q. Dr. Zenger asserts that the company believes the Combined Projects will be "a better deal for ratepayers than FOTs, but it makes no representation that FOTs will be unavailable or unreasonably priced." (Zenger, Supplemental Rebuttal, lines 497–499.) How do you respond?

A. I agree that the Company's position (supported by robust economic analysis) is that, relative to all other resource alternatives—including FOTs—the Combined Projects are a better deal for customers. But this position isn't based on any assumptions that FOTs are "unavailable or unreasonably priced." The Company's position is that FOTs are available, but more expensive than the Combined Projects. The question is whether the Combined Projects are lower cost and lower risk than other resource alternatives, including FOTs. FOTs can be "reasonably priced," yet higher cost than other resource options. And this is precisely what the economic analyses in the 2017 IRP and throughout this proceeding, including the analysis summarized in my second supplemental direct testimony, shows—net customer benefits from a resource portfolio that includes the Combined Projects is less reliant on market purchases and is conservatively expected to generate net customer benefits in 16 of 18 modeled scenarios (nine price-policy scenarios over two different timeframes). Throughout this proceeding, the company has provided analysis that explicitly and overwhelmingly shows that the Combined Projects are superior to all other resource alternatives, including FOTs.

In contrast, Dr. Zenger has not adequately explained why it is in the public interest to pursue a resource portfolio that is more reliant on uncommitted FOTs considering that my economic analysis, which uses conservative assumptions, shows that the company's preferred portfolio would generate net benefits in all but two of 18 modeled scenarios.

Q. Mr. Peaco and Mr. Hayet state that the company has changed its rationale for justifying the Combined Projects. (*See* Peaco Supplemental Rebuttal and Surrebuttal, lines 112–126; Hayet Second Rebuttal, 28–30.) Is this accurate?

A. No. Mr. Peaco and Mr. Hayet appear to believe that the concepts of an economic time-limited opportunity and capacity need are mutually exclusive. Based on this view, Mr. Peaco and Mr. Hayet assert that PacifiCorp's justification for the Combined Projects has changed since the initial application was filed with the Commission last June. This is not true.

The Combined Projects were included in the 2017 IRP, filed with the Commission in April 2017, as an element of PacifiCorp's least-cost, least risk preferred portfolio, which includes resources *needed to reliably meet customer demand* over a 20-year time frame. PacifiCorp has not stated at any point in this proceeding that the Combined Projects are not needed to reliably serve our customers or are being proposed solely as an economic opportunity.

Mr. Peaco describes PacifiCorp's initial application by referencing the direct testimony of Ms. Cindy A. Crane describing the project as "a unique, time limited opportunity for the Company…." (Peaco Supplemental Rebuttal and Surrebuttal, line 121.) Mr. Peaco's omitted a portion of Ms. Cindy A. Crane's testimony, and these omissions change the testimony's meaning. Ms. Crane's testimony reads, in full: "The renewal of the PTCs has created a unique, time-limited *opportunity for the Company to construct critical transmission facilities in eastern Wyoming, while providing substantial customer savings.*" (Crane Direct, lines 206–210, emphasis added.)

Throughout this proceeding, the company has consistently stated that the Combined Projects will provide significant savings to customers and that they represent a unique, time-limited opportunity for the company to construct critical transmission facilities with minimal rate impact. This was true when the company filed its application in this docket and remains true today. The fact that the Company chose to highlight the unique, time-limited opportunity in direct testimony, then focus on need in response to parties' testimony arguing that there is no need does not indicate that the Company "changed positions."

The Combined Projects are unique in that they provide an opportunity to procure resources needed to meet a capacity deficit while delivering economic benefits and much-needed transmission facilities. This is a time-limited opportunity because of expiring PTCs. Contrary to Mr. Peaco's and Mr. Hayet's mischaracterization of the company's application and position in this proceeding, the Combined Projects are both an economic opportunity *and* needed. Mr. Hayet even goes so far as to state: "Had the Company's request been based on a resource need, the June 30, 2017 application would have had an entirely different emphasis." Mr. Hayet is wrong. The Company chose to highlight the benefits of the project in the June 30, 2017 application because the need had been firmly established through the 2017 IRP. The parties' challenge to the need for the project—despite the fact that the company is capacity deficient over all years in the 2017 IRP—was surprising.

Q. Mr. Peaco claims that you noted in your direct testimony "that the resource balance analysis performed for the 2017 IRP showed no need for incremental capacity until 2028 and had no mention of FOTs as a factor." (Peaco Supplemental Rebuttal and Surrebuttal, lines 123–125.) Mr. Hayet similarly states that "the IRP indicated that the Combined Projects were not needed to satisfy…the Company's capacity requirements." (Hayet Second Rebuttal, lines 842–844.) Are these assertions accurate?

A. No. In my direct testimony, I stated that "the load-and-resource balance developed for the 2017 IRP shows that PacifiCorp would not require incremental system capacity to meet its 13-percent planning-reserve margin until 2028, *accounting for assumed coal unit retirements, incremental energy efficiency savings, and available wholesale-power market purchase opportunities*." (Link Direct, lines 111–115, emphasis added.) The term "available wholesale-power market purchase opportunities" used in this statement is a direct reference to uncommitted FOTs and is factually accurate. If one assumes that all available FOTs are procured without regard to cost—which as noted above is apparently what the parties are suggesting and is essentially treating these resources as existing resources—then there would not be a capacity shortfall until 2028. My direct testimony was highlighting that the selection of wind resources before 2028 was a strong indication that these resources would provide customer benefits because they are lower cost than uncommitted FOTs.

Q. Mr. Hayet argues that the fact that the company did not include the Aeolus-to-Bridger/Anticline transmission line as in service in 2024 in its "status quo case in its modeling analysis" indicates the company does not "really believe the transmission line would have to be constructed by 2024…." (Hayet Second Rebuttal, lines 860–862.) Is this a reasonable position?

A. No. Mr. Hayet's position would penalize the company for being conservative in its modeling assumptions. In fact, if the cost for the Aeolus-to-Bridger/Anticline transmission line were included in the base case simulations beginning 2024 (as assumed in PacifiCorp's long-term transmission plan) and assuming no change to in-service capital costs, net customer benefits would increase in all price-policy scenarios by $193 million when assessed through 2036 and by $293 million when assessed through 2050. Including this cost in the base case simulations would result in net customer benefits under all price-policy scenarios (even in the low natural gas, zero CO_2 price-policy scenario), whether analyzed through 2036 or 2050, and highlights a material risk under a "do nothing" scenario.

Q. Both Dr. Zenger and Mr. Peterson assert that you are now arguing that the Combined Projects are an "early acquisition." (Zenger Supplemental Rebuttal and Surrebuttal, lines 512–553; Peterson Supplemental Rebuttal and Surrebuttal, lines 407–410.) Is this an accurate representation of your testimony?

A. No. Dr. Zenger and Mr. Peterson misunderstand my testimony. In response to arguments that this is not an ordinary resource acquisition, I stated: "*At the very least*, the Combined Projects are an early acquisition." (Link Supplemental Direct and Rebuttal, lines 1082–1083, emphasis added). Interpreting this statement to mean that I "admitted" this is an early acquisition, as Dr. Zenger does, ignores the remainder of my testimony in this docket, which clearly and repeatedly states that there is both a near-term need and long-term need for the Combined Projects, as well as the testimony of Mr. Rick A. Vail.

Q. Mr. Mullins claims that the capacity need identified in the 2017 IRP no longer exists when the company's assessment of resource need is updated to account or the most recent, lower load forecast. (Mullins Supplemental Rebuttal lines 779–815.) Is this true?

A. No. In 2021, the first full year that the Combined Projects are in service, the 2017 IRP shows a capacity deficit of 1,023 MW. The updated load forecast summarized in my supplemental direct testimony shows a 428-MW reduction to the coincident peak load forecast in 2021 relative to the load forecast used in the 2017 IRP. Consequently, accounting for the updated load forecast from my supplemental direct testimony, PacifiCorp's capacity deficit in 2021 would be 595 MW (1,023 MW capacity deficit less the 428-MW reduction in coincident peak load). Accounting for this updated load forecast, PacifiCorp's capacity need grows to 3,395 MW by 2036. The capacity contribution of the Combined Projects (without Uinta) is 182 MW (1,150 MW nameplate capacity times 15.8 percent capacity contribution), which is well below the 595 MW of capacity need in 2021 and the 3,395 MW of capacity need in 2036, even after accounting for the updated load forecast used in my supplemental direct testimony.

Q. Did PacifiCorp provide an updated load-and-resource balance in its 2017 IRP Update?

A. Yes. PacifiCorp filed its 2017 IRP Update with the Commission on May 1, 2018. The load forecast used to develop the updated load-and-resource balance in the 2017 IRP Update is the same underlying load forecast that was used in the economic analysis described in my supplemental direct testimony. After accounting for changes in resources and this updated load forecast, the load-and-resource balance in the 2017 IRP Update shows a capacity shortfall of 606 MW in 2021, rising to 3,445 MW by 2036. As noted above, the capacity contribution of the Combined Projects (without Uinta) is 182 MW, which is well below the capacity need identified in updated load-and-resource balance in the 2017 IRP Update.

Q. Mr. Mullins's Confidential UAE-UIEC Exhibit 3.2 attempts to demonstrate that there is no meaningful need for the Combined Projects, and virtually no need for FOTs. (Mullins Supplemental Rebuttal, lines 790–797.) Is his analysis correct?

A. No. Mr. Mullins's calculations misapply hourly load forecast data provided in response to UAE Data Request 5.6. This hourly load forecast data is net of reductions from distributed generation and incremental demand-side-management ("DSM") resources. These items are accounted for separately in Table 5.14 in PacifiCorp's 2017 IRP. Consequently, Mr. Mullins's calculations double count the impact of distributed generation and incremental DSM resources in his attempt to estimate the impact of the updated load forecast on PacifiCorp's load-and-resource balance. Contrary to Mr. Mullins's claims, which are based on faulty calculations, after accounting for the updated load forecast, PacifiCorp continues to show an immediate need for new capacity that exceeds the capacity contribution from the Combined Projects. When accounting for the Combined Projects, PacifiCorp will still need to acquire 424 MW of uncommitted in FOTs in 2021 to maintain a 13-percent planning-reserve margin.

Q. Is the company's position in this case regarding the treatment of FOTs in determining resource need consistent with prior resource acquisition dockets?

A. Yes. When PacifiCorp acquired the Lakeside 2 plant, it developed an updated assessment of resource need to support the competitive solicitation process. In that case, the company described that its updated assessment included certain planned resources from its most recent IRP (the 2008 IRP) and then excluded resources that were eligible to be filled by the resources that bid into the RFP. According to PacifiCorp's need assessment, the "portfolio set-up reflects the appropriate capacity gap for resource selection optimization by the Company's capacity expansion model, System Optimizer." *In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals*, Docket No. 10-035-126, All-Source Request for Proposal Resource Needs Assessment Update at 6 (Oct. 7, 2010). Among the resources removed to create the capacity gap that would be filled by the RFP bids were uncommitted FOTs. Thus, in the Lakeside 2 acquisition analysis, PacifiCorp did not determine its resource position by accounting for all available FOTs. Instead, the company removed the FOTs from its load-and-resource balance to create the capacity need and then let FOTs compete with the resource bids in the RFP process to select the optimal resource portfolio. PacifiCorp is using the same approach here.

Q. Did parties in that case object to the company's treatment of FOTs in determining resource need?

A. It does not appear so. In fact, OCS's testimony in that case described the company's load-and-resource balance without considering FOTs when it analyzed the potential need for additional resources. *In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals*, Docket No. 10-035-126, Witness OCS-1D, lines 62–70 (Mar. 3, 2011). DPU's expert in the Lakeside 2 case also testified that resources from the RFP could be used to displace FOTs. In particular, DPU testified that a second gas plant (the "Apex plant"), in addition to Lakeside 2, could decrease the reliance on FOTs, which "demonstrate[d] that the Apex plant is needed and can make a vital contribution to the Company's negative capacity position." *In the Matter of the*

Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals, Docket No. 10-035-126, Exhibit No. DPU 2.0 at 31-32 (Mar. 3, 2011).

Q. Mr. Peterson asserts that PacifiCorp has "routinely dismissed any [DPU] concerns about front office transactions until the past few months when it discovered a 'need' to replace front office transactions with multi-billion dollar rate base proposals first announced at the very end of the latest IRP process." (Peterson Supplemental Rebuttal and Surrebuttal, lines 496–499.) Is this true?

A. No. Having led the IRP process for several years and having participated in a number of competitive solicitation processes, I am aware of DPU's persistent concerns about relying on FOTs to meet the company's 13-percent planning-reserve margin target. For this reason, I have been surprised by DPU's arguments supporting increased reliance on uncommitted FOT resources in its opposition to the Combined Projects. Finally, I do not agree with Mr. Peterson's assertion that the company has dismissed DPU's concerns with FOTs. Up until now, all other resource alternatives have simply been higher cost.

Q. Dr. Zenger states that the company has not provided any indication that, without the Combined Projects, customers "will not be reliably served at a reasonable cost in the future." (Zenger Supplemental Rebuttal and Surrebuttal, lines 589–591.) How do you respond?

A. Dr. Zenger's testimony implies that resources should only be acquired to meet a projected capacity need only when *all* resource alternatives have been exhausted and the company is on the verge of not being able to reliably serve its customers. In fact, Dr. Zenger goes as far to assert that new resource acquisition should only be pursued in the absence of an adequate, reliable, and reasonably priced system. (Zenger Supplemental Rebuttal and Surrebuttal, lines 474–475.) Dr. Zenger's perspective on this issue is extreme and would require that the company manage its system on the very edge of being able to deliver reasonably priced service for our customers. As the individual responsible for PacifiCorp's resource plan, it is my goal to ensure the company does not find itself in position where its only choice is to acquire a resource or risk reliability.

Q. Dr. Zenger states there is little downside risk to not pursuing the Combined Projects. (Zenger Supplemental Rebuttal and Surrebuttal, lines 591–592.) Mr. Peaco similarly asserts that customers will be "reliably serviced at a reasonable cost in the future" without the Combined Projects and "there is little downside risk for customers in the Combined Projects' absence." (Peaco Supplemental Rebuttal and Surrebuttal, lines 357–359.) Do you agree?

A. No. There are material risks if the Combined Projects are not constructed. Without the Combined Projects, customers would be more exposed to volatility in the market, more exposed to policies that could place a cost on CO_2 emissions, and more at risk of having to incur the cost of the Aeolus-to-Bridger/Anticline transmission line without the benefit of having PTC-eligible wind to offset these costs. As noted above, and without even accounting for market price and CO_2 policy risks, this could burden customers with hundreds of millions of dollars in costs that are not factored into the company's economic analysis. In fact, the company's conservative economic analysis demonstrates that the "do nothing" scenario will *increase* customer costs in 16 of 18 price-policy scenarios.

2017R RFP MODELING AND RESULTS

Q. Please summarize the role of the independent evaluators who monitored the 2017R RFP.

A. The 2017R RFP was overseen by two independent evaluators—one appointed and retained by the Utah Commission, and one appointed by the Public Utility Commission of Oregon ("Oregon Commission") and retained by PacifiCorp. In accordance with the statutes, rules, and policies in Utah and Oregon, the independent evaluator is an *independent* expert appointed and managed by the commission (not PacifiCorp) to ensure that the RFP process was conducted in a fair and unbiased manner and the final shortlist projects are reasonable and consistent with the modeling results used to evaluate bids.

In the 2017R RFP, both independent evaluators were involved from the beginning—providing feedback and recommendations regarding the design and content of the 2017R RFP and actively participating in every stage of the RFP. For its part, PacifiCorp ensured that the independent evaluators had complete and unrestricted access to all information related to the 2017R RFP and kept both independent evaluators informed of developments as they occurred.

Q. Did the independent evaluators provide an assessment of PacifiCorp's benchmark resources bid into the 2017R RFP (*i.e.*, TB Flats I and II, Ekola Flats, and McFadden Ridge II)?

A. Yes. Because the 2017R RFP included benchmark resources, both independent evaluators provided detailed assessments of the benchmark bids to ensure that they were reasonable and would not bias the solicitation in favor of utility-owned resources.

The benchmark review process occurred before any other bids were received to provide additional assurance that the benchmarks were not provided an unfair advantage. Oregon's final independent evaluator report, issued in February 2018, is provided as Highly Confidential and Confidential Exhibit RMP___(RTL-1SR) ("Oregon IE Report"), and Utah's final independent evaluator report, also issued in February 2018, is provided as Highly Confidential and Confidential Exhibit RMP___(RTL-2SR) ("Utah IE Report").

Q. Did the independent evaluators' review confirm the reasonableness of the benchmark bids?

A. Yes. The Utah independent evaluator concluded that (1) PacifiCorp provided detailed information related to the benchmarks that exceeded industry standards, (2) cost estimates were reasonable, and (3) the review, assessment, and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward perception of bias. (Utah IE Report at 44-45.)

The Oregon independent evaluator also conducted a thorough assessment of the benchmarks, noting that when "assessing a utility's own bids in response to the RFP, our greatest concern is that the utility will incorporate cost estimates that have been aggressively estimated and do not characterize the costs of the project accurately." (Oregon IE Report at 10.) To make its assessment, the Oregon independent evaluator "looked at a detailed breakdown of each of the benchmarks costs to determine if any items have been improperly omitted from the cost calculation, and at overall capital cost levels by comparing them to publicly-available data on recent wind generation capital costs." (*Id.*) This "comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors." (*Id.*) The Oregon independent evaluator ultimately found that the benchmarks were acceptable based on three items:

- First, the benchmarks were not deliberately underpriced through omission of any capital cost components.
- Second, the benchmark capital and operating costs appeared reasonable when compared with public data on U.S. wind projects.
- Third, the capacity factors of the benchmarks were reasonable when compared with public data and were supported by credible third-party analysis.

(*Id.* at 10–11.)

Q. Did the independent evaluators provide any overall conclusions related to the 2017R RFP?

A. Yes. The Utah independent evaluator supported the final shortlist projects based on the following conclusions:

- The 2017R RFP was fair, reasonable, and generally in the public interest. (Utah IE Report at 70.)
- The bid evaluation and selection processes were designed to lead to the acquisition of wind-generated electricity at the lowest reasonable cost based on the detailed state-of-the-art portfolio evaluation methodology used, the steps taken to achieve comparability between utility cost-of-service resources and third-party firm priced bids, the flexibility afforded bidders via a range of eligible resource alternatives, and the attempt to allow for equal terms for PPA and build-transfer agreement ("BTA") resources. (Utah IE Report at 71.)
- PacifiCorp's modeling demonstrates that the Combined Projects "should result in significant savings for customers." (Utah IE Report at 83.) Further, because PTCs will flow through to customers in the first ten years, the "near-term benefits to customers should be significant." (Utah IE Report at 83.)

The Oregon independent evaluator also recommended that the Oregon Commission approve PacifiCorp's final shortlist based on the following conclusions:

- The selected bids represent the top offers that are viable under current transmission planning assumptions and provide the greatest benefits to ratepayers.

- The selected bids represent the best viable options from a competitive perspective, based on the 59 bid options presented.

- The independent evaluator's analysis confirmed that the selected bids were reasonably priced and, while not the lowest-cost offers, were the lowest-cost offers that were viable under current transmission planning assumptions. The independent evaluator's analysis included its own cost models for each bid option and a review of PacifiCorp's models.
- The independent evaluator took special care to confirm the selection of PacifiCorp's benchmark resources. The independent evaluator confirmed the accuracy of the benchmark costs and scoring. The independent evaluator noted that the benchmark bids were disciplined by the fact that a third-party bidder submitted a competing offer for a BTA for benchmark projects.

- The independent evaluator confirmed that the 2017R RFP aligns with the 2017 IRP.

(Oregon IE Report at 2–3.)

Q. Please respond to Messrs. Peaco's, Hayet's and Mullins's claims that PacifiCorp's changes to its economic modeling for purposes of developing the final shortlist for the 2017R RFP unfairly biased the results. (Peaco Supplemental Rebuttal and Surrebuttal, lines 842–859; Hayet Second Rebuttal, lines 353–356; Mullins Supplemental Rebuttal, lines 463–468.)

A. As explained in my supplemental direct testimony, when comparing bids in the 2017R RFP portfolio development phase, PTC benefits were applied on a nominal basis rather than a levelized basis for self-build and BTA bids to better reflect how the PTC benefits flow through customer rates. (Link Supplemental Direct and Rebuttal, lines 38-41.) This refinement better aligns project costs and benefits and impacts only the SO model and PaR results through 2036. This modeling refinement had no impact on the nominal revenue requirement calculations that were also reported in my supplemental direct and second supplemental direct testimonies.

This modeling refinement was necessary as part of the 2017R RFP bid evaluation and selection process because this was the first time that the SO model was used to select PTC-eligible wind proposals offered under different commercial structures where those commercial structures directly influence the magnitude and timing of expected costs in customer rates. Under company-owned commercial structures (benchmarks and BTAs), PTC benefits will flow through to customer rates over the first ten years after those wind facilities are placed in service. In contrast, wind facilities offered into the 2017R RFP as a PPA were not priced by bidders to reflect the substantial near-term benefits of PTCs. The difference in present-value customer impacts between these two types of commercial structures has not traditionally been a factor in an IRP, where all proxy wind resources are assumed to be company-owned assets for planning purposes. The company's modeling refinement did not bias the results of the 2017R RFP as Mr. Peaco, Mr. Hayet and Mr. Mullins claim. To the contrary, this modeling improvement was necessary to ensure bid selections appropriately accounted for the timing of PTC benefits between company-owned and PPA commercial structures.

Q. Did you continue to use levelized capital costs during the portfolio development phase of the 2017R RFP bid evaluation and selection process?

A. Yes.

Q. Why is it appropriate to reflect nominal PTCs while continuing to levelize capital revenue requirement in the 20-year modeling through 2036?

A. The IRP models select least-cost portfolios based on present-value system costs. It would not be appropriate to include nominal revenue requirement from capital investments for assets having a depreciable life that extends beyond the 20-year IRP study period in any present-value calculation. It would only be appropriate to include capital revenue requirement on a nominal basis in present-value calculations when those calculations cover the full life of the proposed new wind facilities.

In contrast, it is appropriate to consider nominal PTC benefits in the IRP models because all of these benefits will be realized within the 20-year time frame of those studies. Because PTC benefits will be fully realized within the 20-year time frame of these studies, the impact of applying nominal PTCs when developing present-value calculations is precisely the same impact that would occur if PTCs were levelized over their 10-year life. Consequently, with the improved modeling methodology, PacifiCorp's IRP models appropriately weight the front-end loaded PTC benefits without disproportionately weighting capital costs in its present-value calculations.

This improved treatment of PTCs simply ensures that present-value calculations in the 20-year analysis are based on a stream of annual costs and benefits that consistently applies levelization over the period in which those costs and benefits are expected to occur—30 years for capital revenue requirement, 10 years for PTC benefits, and annually for non-PTC system benefits and run-rate O&M.

The company used this approach—ensuring that present-value calculations reflect costs and benefits that are levelized over the period in which they are expected to occur—without controversy when it requested approval of its voluntary resource decision to install emission control equipment at its Jim Bridger Unit 3 and Unit 4 coal units and when it conducted coal-plant analysis in its IRPs. The improved modeling used here simply conforms the treatment of PTCs to the treatment of other costs and benefits.

Q. Does PacifiCorp intend to model PTCs in this manner in its IRPs?

A. Yes. Because modeling PTCs on a nominal basis better reflects how they are treated in rates, PacifiCorp adopted this same treatment in its recently filed 2017 IRP Update and intends to use this approach in future IRPs.

Q. Did the independent evaluators overseeing the 2017R RFP object to PacifiCorp's refined modeling?

A. No. Both independent evaluators overseeing the 2017R RFP were informed of PacifiCorp's decision to model PTC benefits on a nominal rather than levelized basis, and neither concluded that the refinement biased the bid-evaluation results. In fact, the sensitivity analysis requested by the independent evaluators that I described in my supplemental direct testimony was designed to specifically test whether the refined modeling of PTC benefits unreasonably biased the resource selection. (Link Supplemental Direct and Rebuttal, lines 252–277.)

Q. Did the Utah independent evaluator discuss this treatment of PTCs in the portfolio-development phase of the 2017R RFP?

A. Yes. The Utah independent evaluator noted a concern that the PTC modeling could produce a bias in favor of utility-owned resources "if only a portion of the capital costs associated with the benchmarks and BTAs are recovered during the 20-year evaluation period, since these projects have a 30-year life and capital cost recovery period." (Utah IE Report at 62.) In response, the Utah independent evaluator described the additional analysis provided by the company, along with several meetings with the independent evaluators to discuss this issue. The Utah independent evaluator observed in his report that PacifiCorp "refuted the basis for evaluating PTCs on a levelized cost basis since [PacifiCorp] would flow through all the customer costs in the near-term." (Utah IE Report at 62.) Further, according to the Utah independent evaluator, PacifiCorp "also provided a 30-year analysis of the costs and benefits of the initial portfolio [*i.e.*, the portfolio with utility-owned resources] and the updated portfolio [*i.e.*, the portfolio with PPAs] . . . to demonstrate that the original portfolio would still provide greater benefits over a 30-year timeframe." (Utah IE Report at 62.)

When PacifiCorp presented its final shortlist to the independent evaluators, the Utah independent evaluator confirmed his conclusions from the portfolio-development stage, explicitly concluding that the revised shortlist portfolio provides greater near-term benefits than the PPA sensitivity:

> PacifiCorp also addressed two of the IEs concerns raised in discussions on shortlist evaluation and selection. The first issue dealt with the application of the PTCs in the evaluation methodology. As noted, PacifiCorp's analysis assumes that the PTC inputs to the SO model would be based on nominal dollar values since the actual benefits would be flowed through to customers. The Oregon IE requested a sensitivity where the PTC benefits produced by BTA and benchmark options would be levelized over the full 30-year life of the project. A second issue raised by the IEs was whether the term of the analysis through 2036 (approximately 16 years) and the real levelized cost treatment for capital revenue requirements adequately reflects all the capital costs associated with utility ownership options over a thirty-year project life. In response, PacifiCorp completed an analysis of the expected benefits and costs through 2050 comparing the results of PacifiCorp's selected portfolio and the IE sensitivity case. In its presentation, PacifiCorp concluded that the PVRR(d) benefits through 2036 from the final

> shortlist portfolio total $343 million and the benefits from the IE Sensitivity with the PPA included in the bid portfolio total $277 million. Through 2050, the benefits from the final shortlist bid portfolio of $223 million are closely aligned with the IE Sensitivity bid portfolio that provides an estimated $224 million in benefits through 2050. The revised shortlist portfolio provides greater near-term benefits.

(Utah IE Report at 65.)

Q. Did the Utah independent evaluator conclude that the self-build or BTA bids received a preference as a result of PacifiCorp's modeling?

A. No, quite the opposite. The Utah independent evaluator concluded that the results of the sensitivity (discussed above) "indicated that there did not appear to be an inherent advantage associated with a utility-ownership bid due to the shorter evaluation period for purposes of evaluating and selecting a portfolio of resources." (Utah IE Report at 75.) The independent evaluator explained that the "net benefits approach used may eliminate the costs for a longer-term resource but also eliminates the revenue side of the equation, which would likely be escalating over time." (Utah IE Report at 75.) Thus, the company's modeling "allows for a consistent and fair evaluation of bids of different technologies and terms and is a reasonable tool for initial evaluation of bids." (Utah IE Report at 75.)

Q. Did the Oregon independent evaluator discuss this treatment of PTCs in the portfolio development phase of the 2017R RFP?

A. Yes. The Oregon independent evaluator expressed concern that levelizing the PTC benefits caused the SO model to select PPAs instead of self-build and BTA bids. (Oregon IE Report at 29-30.) The Oregon independent evaluator specifically noted that the PTC-modeling refinement "had no impact on winning projects selected in this RFP" because several of the PPAs that were selected in the sensitivity requested by the independent evaluators were ultimately non-viable projects. (Oregon IE Report at 5.)

Q. Mr. Mullins claims that the RFP selection process was biased because the Company "disqualified" projects based on interconnection queue position (Mullins, Supplemental Rebuttal, lines 275–413.) Mr. Peaco also identifies the "last minute elimination of essentially all projects" due to the restudy process as a "significant failure" in the RFP process. (Peaco Supplemental Rebuttal and Surrebuttal, lines 379–381.) And Mr. Hayet likewise claims that the company "determined bids had to be eliminated…." (Hayet Second Rebuttal, lines 726–730.) Are the witnesses accurately describing the impact of the interconnection restudies on the RFP process?

A. Absolutely not. No bids were "disqualified" or "eliminated" from consideration due to interconnection queue position. The final shortlist was initially developed based on economic analysis of the bids—without consideration of interconnection queue position, as discussed in more detail below. Only one change to the final shortlist was made based solely on the results of the interconnection restudies—the removal of McFadden Ridge II because it could not be interconnected with just the addition of the Aeolus-to-Bridger/Anticline transmission line.

Even more importantly, any allegations that the interconnection queue issues "biased" the RFP process are directly contrary to the conclusions of the independent evaluators who monitored the 2017R RFP. Both independent evaluators provided their own independent analysis and carefully scrutinized the process and results. And both independent evaluators concluded that the 2017R RFP was transparent, fair, and unbiased.

Q. You note that the independent evaluators addressed the interconnection queue issue. What did the independent evaluators conclude?

A. Yes. Both independent evaluators agreed with PacifiCorp's assessment that projects with interconnection queue positions lower than Q0712 were non-viable. Although both independent evaluators expressed some frustation about the limitations imposed by these issues, both concluded that the process was nonetheless fair, transparent, and unbiased. The Utah independent evaluator found that the final shortlist of projects "was a reasonable selection based on the constraints identified." (Utah IE Report at 84.) The Oregon independent evaluator explained that PacifiCorp's "transmission arm, which assesses interconnection costs, must, by law, assume that each queue project is interconnected in order received so each project assumes that all projects ahead of it in the queue are interconnected." (Oregon IE Report at 32.) Thus, "[a]s more projects in the Wyoming area are interconnected it puts more strain on the transmission system until eventually major upgrades such as the Gateway West and South projects are needed." (Oregon IE Report at 32.) In this case, the major upgrades were required for all projects with queue positions lower than Q0712. The Oregon independent evaluator concluded that it "understand[s] and appreciate[s] PacifiCorp's position and do[es] not disagree with their transmission department's findings (beyond noting the obvious fact that many projects will likely drop out of the queue and that actual interconnection costs will differ from projected)." (Oregon IE Report at 35.) According to the independent evaluator, "[t]o go forward with projects that cannot meet the proposed online date without major accelerated transmission investment would not seem to be the wisest course of action." (Oregon IE Report at 35.)

Q. Is the fact the independent evaluators disagree with Mr. Mullins's claim notable?

A. Yes. Mr. Mullins appears to only selectively rely on the independent evaluators, citing their conclusions when they support his position, but ignoring or dismissing their conclusions when they do not support his position.

Q. Mr. Mullins claims that the company never disclosed the possibility that a bidder's interconnection queue position could impact the viability of its project. (Mullins Supplemental Rebuttal, lines 175–187; 209–217; 211–224; 291–300.) Is this accurate?

A. No. The fact that there was limited interconnection capability was known at the beginning of the 2017R RFP process, which is why PacifiCorp's initial minimum bid-eligibility screen included a requirement for an interconnection system impact study. Commenters and bidders requested that this requirement be removed from the minimum bid-eligibility screen to allow broader participation. At the recommendation of the independent evaluators, this restriction was changed to generators who had begun the interconnection study process.[1] This change increased the number of projects that could bid into the 2017R RFP, which resulted in robust participation, including numerous bids that were not dependent on the construction of the Aeolus-to-Bridger/Anticline line. Although transmission constraints ultimately rendered some bids non-viable, neither of the independent evaluators indicated that the 2017R RFP process was biased or unreasonable as a result.

[1] *See Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources*, Utah PSC Docket No. 17-035-23, Hearing Transcript, page 56, lines 4–10 (Sept. 19, 2017).

Q. Mr. Peterson also reiterates the Utah IE's claim that the company should have held a transmission workshop during the RFP process so that potential bidders understood the interconnection constraints on the Company's system. (Peterson Supplemental Rebuttal and Surrebuttal, lines 118–122.) Was the transmission workshop referenced by the Utah IE actually held?

A. Yes. Contrary to the IE's final report, the company did hold the transmission workshop. PacifiCorp identified in its released RFP that it would reserve a specific time in its October 2, 2017 bidder workshop to cover interconnection and transmission service issues and followed through with specific discussions on the topic, as noted in its bidder workshop presentation deck. PacifiCorp also responded to multiple bidder questions on interconnection and transmission service, reviewed those with the independent evaluators, and posted the responses to the RFP website.

Q. Mr. Mullins also claims that the company's "treatment of transmission costs" was inconsistent with its communications with bidders in the period leading up to the 2017R RFP. Is this true?

A. No. Mr. Mullins claims that contrary to communications with bidders, the company directly assigned to bidders with queue positions at Q713 or higher the "costs associated with providing transmission capacity in order to relieve existing congestion and facilitate the interconnection and integration of new wind projects"—including the costs of Gateway South. (Mullins Supplemental Rebuttal, lines 228–241.) Mr. Mullins is wrong.

Mr. Mullins correctly states that the company informed bidders that costs associated with the Aeolus-to-Bridger/Anticline transmission line, which relieves congestion and enables interconnection, would not be assigned to individual projects. And this is exactly what PacifiCorp did in the bid-evaluation project. Contrary to Mr. Mullins's claims, at no point did PacifiCorp put the costs of any component of PacifiCorp's long-term plan on bids (whether the Aeolus-to-Bridger/Anticline line or other elements of Energy Gateway).

To the extent Mr. Mullins is claiming that PacifiCorp told bidders that interconnection costs required to receive *interconnection* service, which are specific to any individual wind facility, would not be accounted for in the company's bid selection and evaluation process, he is incorrect. One of the minimum bid-eligibility requirements explicitly identified in the 2017R RFP clearly states that bids could be disqualified if bidders failed to provide interconnection costs. In specifying this minimum bid-eligibility requirements, the 2017R RFP document further states that cost estimates are required even if a study from the transmission provider was not completed or available at the time bids were due. Clearly, PacifiCorp would not have established this minimum bid-eligibility requirement, which if not met could disqualify a bid, if it did not intend to use this information to evaluate bids submitted into the 2017R RFP.

Q. Mr. Mullins claims that he was "under the impression that the bids would be evaluated on the same basis," including equalization or mitigation of any benefits that one bidder may have due to queue position. (Mullins Supplemental Rebuttal, lines 277–289.) How do you respond?

A. As described throughout my previous testimony and this testimony, the bids *were* evaluated on the same basis. Mr. Vail addresses Mr. Mullins's unfounded allegations that PacifiCorp could have somehow addressed queue position through bid analysis.

Q. Mr. Mullins claims that because "PacifiCorp applied incremental transmission costs to the bids whose queue position exceeded the incremental transmission capacity, the higher queue position resources had no way of being selected by the model." (Mullins Supplemental Rebuttal, lines 320–328.) Is this true?

A. No. In fact, my supplemental direct testimony describes the bid evaluation and selection process that was completed *before* considering the results of the interconnection restudy process. The original final shortlist of bids summarized in that testimony included the same projects selected to the updated final shortlist summarized on my second supplemental direct testimony except that the original final shortlist included the McFadden Ridge II benchmark bid. In direct contradiction to the claims made by Mr. Mullins, the original bid evaluation and selection process performed by PacifiCorp and monitored by two independent evaluators demonstrates that the interconnection restudy process did not prevent, in any way, the selection of projects because of their interconnection queue number.

Q. Based on this understanding, Mr. Mullins then argues that there is no way to know if the best resources were actually selected to the final shortlist. (Mullins Supplemental Rebuttal, lines 320–328.) Is this true?

A. No. As discussed above, Mr. Mullins's assertion is contrary to basic facts and, therefore, fundamentally flawed. Before considering results of the interconnection restudy process, the only interconnection-related constraint was the assumption that total interconnection capability with the addition of the Aeolus-to-Bridger/Anticline transmission line would be 1,270 MW. The interconnection restudies performed after the original final shortlist was determined resulted in the following conclusions:

(1) That the TB Flats I and II and Cedar Springs projects could interconnect with the addition of the Aeolus-to-Bridger/Anticline transmission line and no other elements of the company's long-term plan;

(2) That McFadden Ridge II could not interconnect without additional elements of the company's long-term transmission plan, namely Gateway West and Gateway South; and

(3) That additional interconnection capability would be created with the addition of the Aeolus-to-Bridger/Anticline transmission line, which allowed McFadden Ridge II to be replaced with Ekola Flats.

Rather than limiting the outcome of the 2017R RFP, the interconnection restudy process provided new information that allowed the inclusion of a more economic project because of increased interconnection capability. The only thing that was preventing the models from choosing Ekola Flats over McFadden Ridge II in development of the original final shortlist was the original 1,270-MW limit on interconnection capability.

Mr. Mullins also ignores the fact that the interconnection considerations resulted in PacifiCorp proposing to replace *only one shortlist bid*, with all other shortlist bids remaining unchanged. More specifically, the interconnection restudy process provided new, more updated information that caused PacifiCorp to exclude the McFadden Ridge II benchmark bid. While the new and more updated information from the interconnection restudy process demonstrates that projects with an interconnection queue number greater than Q0712 would not be viable at this time, this information had no impact on selection of the best resources other than allowing the more-economic Ekola Flats benchmark bid to replace the McFadden Ridge II benchmark bid.

This single shortlist change resulting from interconnection restudies can hardly be described as interfering with the value of the company's entire competitive solicitation process. Allowing participation without regard to interconnection queue position or study status resulted in a robust competitive solicitation, including numerous bids that were not enabled by construction of the Aeolus-to-Bridger/Anticline transmission line. Interconnection considerations, based on the most current and up-to-date information, caused the replacement of a single project and did not unravel those benefits. To the extent Mr. Mullins is arguing that the original (pre-interconnection considerations) shortlist should have included lower-queued projects for other, non-interconnection-related reasons, these arguments are inconsistent with the results of the economic evaluation of the bids and should be disregarded.

Q. Mr. Mullins claims that PPA bids were lower risk and therefore better alternatives and that these alternatives were eliminated based only on their interconnection queue position. (Mullins Supplemental Rebuttal, lines 322-340.) Is this true?

A. No. As described above, the preliminary shortlist of bids that was selected *before* the interconnection restudy process was finalized included all but one of the same resources that are included in the updated final shortlist. Moreover, as discussed in my supplemental direct testimony, at the request of the independent evaluators, PacifiCorp conducted a sensitivity to specifically test whether the highest performing PPAs bid into the RFP could displace the bids selected to the preliminary shortlist. This sensitivity study, which did not impose any limitations on resource selection based on interconnection queue position, shows that the PPAs were not superior resource selections.

Q. Mr. Mullins suggests that the Wind Projects are higher risk than PPAs because customers are insulated from risks when the company executes PPAs, whereas customers bear risks for utility-owned resources (*e.g.*, the risk of construction cost over-runs and PTC "unavailability"). (Mullins Supplemental Rebuttal, lines 329–340.) How do you respond?

A. I disagree. Mr. Mullins ignores the fact that customers also receive upside benefits for utility-owned resources that they do not receive under a PPA. For example, customer benefits from the Combined Projects associated with reduced O&M costs, increased generation levels, and terminal value provide customer benefits that are not available through a PPA. In each of these cases, customers will receive the increased benefits because of the nature of cost-of-service ratemaking. Under a PPA structure, on the other hand, project owners receive all the upside benefits. PPAs can provide some amount of certainty, but that certainty can both benefit and harm customers.

Moreover, a utility self-build or BTA project provides substantial long-term benefits that customers never receive under a PPA. Once a PPA term expires, customers walk away with nothing. If the utility owns the resource, however, customers will continue to receive the benefits of that resource for as long as it operates, and even after the resource is no longer operational, customers retain the value associated with the land and facilities that have lives that extend beyond the life of the generating resource.

UPDATED ECONOMIC ANALYSIS

Q. Messrs. Peaco, Hayet, and Mullins and Ms. Kelly claim that the nominal treatment of PTCs has the potential to bias model results for the 20-year study period and does not provide a reasonable estimate of both the costs and the benefits of the Combined Projects. (Peaco Supplemental Rebuttal, lines 842–859; Hayet Supplemental Rebuttal, lines 303–466; Mullins Supplemental Rebuttal, lines 437–474; Kelly Response Testimony, lines 132–137.) How do you respond?

A. As I discussed earlier, the rationale for applying PTC benefits on a nominal basis is reasonable and necessary to align the 20-year economic analysis with how PTC benefits will flow through to customers in rates. It is appropriate that the company continue to apply revenue requirement associated with capital costs on a levelized basis, because 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, which extends beyond 2036 (the last year of the 20-year modeling period). In contrast, PTC benefits will flow to customers during the first 10 years after the new equipment is installed at the proposed wind facilities. Consequently, the timing of the PTC benefits should be appropriately weighted and accounted for in the present-value calculation of net benefits.

Q. Mr. Hayet calculates the 20-year benefits from the Combined Projects (with Uinta) using nominal capital costs with nominal PTCs and concludes that the benefits in each price-policy scenario drop by $75 million. (Hayet Second Rebuttal, lines 425–448.) How do you respond?

A. On its face, it is perfectly rational to consider nominal revenue requirement for capital investments over any time period. However, for the reasons described in my supplemental direct testimony and in this surrebuttal testimony, it is not appropriate to include nominal revenue requirement from capital investments for assets having a depreciable life that extends beyond the 20-year IRP study period in *present-value* calculations based on model results through 2036. Mr. Hayet asserts that the 20-year analysis, with the application of levelized capital costs, understates revenue requirement and that his calculations inappropriately estimate the impact of this assumption in single present-value figure. This is particularly problematic when including nominal revenue requirement costs for transmission facilities assumed to have a 62-year life, where these assets are expected to be in service for additional 46 years beyond the 20-year IRP planning period. Mr. Hayet fails to recognize that the present-value results from the IRP models are intended to assess the relative difference in system costs among different resource portfolios over a 20-year planning time frame. The present-value results from the IRP models are not intended to forecast annual rate impacts between different resource portfolios.

Throughout this proceeding, my testimony has presented an annual revenue requirement analysis of the Combined Projects to specifically address directional rate implications in nine different price-policy scenarios. In this analysis, it is appropriate to consider the nominal revenue requirement from capital costs in the present-value calculations because it spans the full 30-year life of the new wind facilities. Importantly, as summarized earlier in my testimony, the present-value results from the nominal revenue requirement analysis demonstrate that the Combined Projects (without Uinta) are conservatively expected to produce net customer benefits in seven of nine price-policy scenarios, and these benefits are expected to occur over both the near and long terms. Importantly, even if one were to assume that Mr. Hayet's present-value calculations are valid for the 20-year IRP analysis—and to be clear, the company is not saying this calculation is valid—the Combined Projects still generate net customer benefits in seven of the nine price-policy scenarios. In fact, Mr. Hayet's table summarizes 20-year results using three different calculations, and in aggregate, 23 of 27 scenarios show net customer benefits with an average present-value net benefit of $227 million.

Q. Ms. Kelly does a similar calculation and concludes that the benefits in each price-policy scenario drop by $77 million. (Kelly Response Testimony, lines 227–236.) How do you respond?

A. Ms. Kelly did not supply work papers with her testimony, so I was not able to identify why her estimated impact of applying nominal capital revenue requirement in the 20-year studies differs from Mr. Hayet's estimates. The company's treatment of PTCs and capital revenue requirement appropriately accounts for the front-loaded PTC benefits without overstating capital revenue requirement, which extends beyond the 20-year time frame simulated with the IRP models. Nonetheless, Ms. Kelly's analysis similarly shows that, based on her calculations, the Combined Projects are expected to produce net customer benefits in seven of nine price-policy scenarios.

Q. Mr. Mullins concludes that while PacifiCorp's new modeling approach ensures that the entirety of PTC benefits will be captured in the 20-year economic evaluation, some of the transmission and other capital-related revenue requirements will be excluded from that 20-year analysis. (Mullins Supplemental Rebuttal, lines 455–468.) Do you agree?

A. Yes. In fact, and as I discussed earlier, this is appropriate when using the SO model, which simulates PacifiCorp's system through 2036, to select among different bids offered under different commercial structures. In the 20-year IRP analysis, application of nominal PTC benefits and levelized capital revenue requirement appropriately reflects the relative difference in the present-value benefits and costs from a resource portfolio that includes the Combined Projects with a resource portfolio that does not include the Combined Projects. Interestingly, in asserting that certain costs are not captured in PacifiCorp's 20-year IRP analysis, Mr. Mullins fails to mention that this analysis also does not capture any benefits that the Combined Projects will generate beyond the 20-year time frame.

Q. Mr. Hayet asserts that through the nominal treatment of PTCs and levelized treatment of capital costs, the company maximized the inclusion of PTC benefits but minimized the inclusion of capital revenue requirements in its economic analysis, thereby increasing the benefits of each project. (Hayet Second Rebuttal, lines 258–359.) Is this accurate?

A. No. As discussed above, PacifiCorp's approach to calculating the change in present-value system costs between resource portfolios with and without the Combined Projects in the 20-year IRP analysis is appropriate. It is only appropriate to include capital revenue requirement on a nominal basis in present-value calculations when those calculations cover the full life of the proposed wind facilities. That conservative analysis, including Uinta, is included in my supplemental direct testimony, and without Uinta, is summarized earlier in this surrebuttal testimony. The analyses demonstrate that the Combined Projects are expected to generate net customer benefits in seven of nine price-policy scenarios before considering upside benefits from potential renewable-energy credit ("RECs") revenues, operations and maintenance ("O&M") cost savings, application of less conservative system benefit assumptions beyond 2036, an approximately 200 MW increase in transfer capability across the Aeolus-to-Bridger/Anticline transmission line, and application of Aeolus-to-Bridger/Anticline transmission costs in base case simulations without the proposed new wind projects.

Q. Mr. Mullins applies certain modeling adjustments that more than eliminate the $167 million in net benefits projected in the company's nominal revenue requirement analysis economic analysis through 2050 (including Uinta). Are these adjustments valid?

A. No. Mr. Mullins applies adjustments related to ongoing transmission capital, OATT transmission revenues, energy-imbalance market ("EIM") uninstructed imbalance costs, EIM transmission, and a reduction in market prices. I address each of these items in turn below.

Q. Mr. Mullins claims the company did not consider ongoing capital maintenance costs for the Transmission Projects, and that if these costs are considered it would reduce net benefits from the Combined Projects. (Mullins Supplemental Rebuttal, lines 482–511.) Do you agree?

A. No. Mr. Vail explains how Mr. Mullins mischaracterized PacifiCorp's response to UAE Data Request 5.4, and clarifies that the company does not expect an increase to overall capital maintenance costs, let alone run-rate capital expenditures that equate to 100 percent of the initial investment. Moreover, even if total system run-rate capital expenditures were to increase after the Aeolus-to-Bridger/Anticline line is placed in service, it would not be appropriate to include the impact of these costs beyond 2050, which I understand is what Mr. Mullins refers to as the "terminal period." This approach inappropriately assigns costs without consideration of offsetting benefits from the new transmission line that will persist well beyond 2050. Consequently, Mr. Mullins's adjustments related to ongoing capital expenditures for the Aeolus-to-Bridger/Anticline transmission line are not valid and should be rejected.

Q. Mr. Mullins claims the company has applied faulty assumptions for incremental transmission revenue credits. (Mullins Supplemental Rebuttal, lines 600–670.) Mr. Peaco also questions the company's transmission revenue assumptions. (Peaco Supplemental Rebuttal and Surrebuttal, lines 401–410.) How do you respond?

A. Mr. Vail explains that transmission costs are allocated among transmission customers based primarily on load, that Mr. Mullins misunderstands how transmission rates are calculated, and that PacifiCorp's incremental transmission revenue credit assumptions are conservative, not high.

In addition, Mr. Mullins's calculations are wrong. Mr. Mullins takes a $72 million dollar benefit from the transmission revenue credits, which is 12 percent of the $602 million present-value cost (calculated off of nominal revenue requirement cost through 2050) and reduces it by 0.38 percent to 11.62 percent. Mr. Mullins then applies this change in percentage to the total annual transmission revenue requirement instead of the transmission revenue requirement associated with just the Aeolus-to-Bridger/Anticline transmission line. Transmission revenue requirement that is not associated with the Aeolus-to-Bridger/Anticline transmission line would change with changes to the percentage of costs paid by third-party transmission customers regardless of whether this line is included in rate base. If one were to assume an alternative percentage, it would only apply to the incremental cost of the Aeolus-to-Bridger/Anticline transmission line. Correcting Mr. Mullins's error would reduce his calculated adjustment, which is not necessary to begin with, from $25.7 million to $2.3 million. Mr. Mullins's adjustments related to OATT transmission revenues are not necessary, calculated in error, and should be rejected.

Mr. Peaco takes his criticism of OATT transmission revenues to the extreme, and calculates revised net benefit results that completely eliminate these benefits because he believes they are speculative and highly uncertain. (Peaco Supplemental Rebuttal and Surrebuttal, lines 811-823). As noted by Mr. Vail, transmission revenues are not speculative and highly uncertain, and if anything, the company's assumptions are conservative. Consequently, Mr. Peaco's adjustment for OATT transmission revenues is unnecessary, not supported, and should be rejected.

Q. Mr. Mullins again argues that the Company has not accounted for energy EIM uninstructed imbalance charges. (Mullins Supplemental Rebuttal, lines 719–724.) Can you please explain uninstructed imbalance charges?

A. Yes. First, I will provide more context for the explanation and describe how EIM settlements are calculated for PacifiCorp's resources. In the EIM, the company provides a base schedule for all of its participating and non-participating resources, including variable energy resources such as wind facilities. The base schedules are hourly and are used by the California Independent System Operator ("CAISO") for purposes of a balancing test to ensure that the company has scheduled its resources within one percent of its expected demand in the upcoming hour. The next step in the scheduling process is the 15-minute schedule, which is generated approximately 30 minutes before the operating interval for each resource in PacifiCorp's system. This fifteen-minute schedule is considered an advisory schedule because it is not used for dispatch purposes. Finally, there is a five-minute schedule, which is a dispatch instruction to each of PacifiCorp's resources, including expected wind output for the five-minute interval. Each of these three schedules—hourly, 15-minute and five-minute—is used to calculate the instructed imbalance market settlements for a resource.

For the uninstructed imbalance settlement, the CAISO uses the variance in the actual submitted meter data for a resource, the five-minute dispatch instruction, and the five-minute locational marginal price at the resource node. The difference between the five-minute dispatch instruction and the actual meter data is multiplied by the locational marginal price and divided by 12 (division by 12 is required because the time frame is a five-minute interval, and there are 12 five-minute intervals in an hour). This calculation results in a charge to a resource if it produced less energy relative to the schedule. Conversely, this calculation results in a payment to a resource if it produced more energy relative to its schedule.

Q. In the company's supplemental direct and rebuttal filing, Mr. Vail testified that the company expects that the uninstructed imbalance charges should be neutral over the life of the resource. (Vail Supplemental Direct and Rebuttal, lines 711–728.) Mr. Mullins argues that Mr. Vail was wrong. (Mullins Supplemental Rebuttal, lines 725–736.) How do you respond?

A. As explained by Mr. Vail, the uninstructed imbalance charges are a reflection of forecast error (actual meter data minus a five-minute forecast). Assuming that the forecast, which is produced less than 30 minutes before the interval, has an equal chance of being higher or lower over the life of a resource, the net charges should be close to zero.

Mr. Mullins provides evidence related to two resources over a short period of time to argue that there is an inherent bias in the forecasting. But the alleged bias is simply the result of Mr. Mullins's reliance on a limited data set and is not reflective of long-term expectations, which are that the net outcome will be closer to zero.

Q. Are there any other flaws in Mr. Mullins's analysis?

A. Yes. The existence of uninstructed imbalance charges assigned to certain resources does not mean that there is an actual cost (or revenue) that is passed through to customers. Uninstructed imbalance reflects the movement of resources and load that are outside of the CAISO's dispatch, and PacifiCorp is therefore required to manage that variation using its regulating resources as the balancing area authority. PacifiCorp must manage its area-control error as close to zero as possible to maintain its balancing and frequency requirements in accordance with the National Electric Reliability Council's standards. Thus, if a wind resource was five MW above its CAISO dispatch (five-minute forecast), then another resource, likely a regulating resource, on the PacifiCorp system would need to decrease by five MW to maintain system balance.

Q. When the regulating resource moves in the opposite direction of the wind resource, is that considered uninstructed imbalance?

A. Yes. The movement would be uninstructed imbalance because it was not part of the CAISO's dispatch solution. When PacifiCorp regulates with its resources for changes in wind, solar, and load outside of the CAISO's dispatch, that is considered regulation and is maintained by keeping several of PacifiCorp thermal units in "regulating mode" to make sure that PacifiCorp's system-balancing requirements are met.

Q. Does that mean there is a reciprocal cost or revenue for PacifiCorp's regulating resources?

A. Yes. While Mr. Mullins includes a table that shows a cost for the wind facilities' uninstructed imbalance, what he does not show is the corresponding revenue that was received by one of PacifiCorp's regulating resources.

Q. Is there a cost for regulating for variable-energy resources?

A. Yes. There is a cost for regulating for variable-energy resources, which is why PacifiCorp includes an integration cost in its economic analysis, consistent with the company's application of an integration cost in the IRP.

Q. If the Commission used Mr. Mullins's assessment of the uninstructed imbalance costs for the new wind facilities, would that be double counting the costs of integration?

A. Yes. As noted above, integration costs are already included in the company's economic analysis. Mr. Mullins's adjustment for EIM uninstructed imbalance charges is based on a limited data set that ignores expected long term trends, ignores offsetting revenues from regulating resources, and, as noted, double counts the cost of wind integration already factored into the company's economic analysis. Consequently, Mr. Mullins's EIM uninstructed energy imbalance adjustment should be rejected.

Q. Mr. Mullins also claims that PacifiCorp improperly considered EIM benefits by assuming there is a 300 MW transmission connection between the company's east and west balancing authority areas. (Mullins Supplemental Rebuttal, lines 673–710.) How do you respond?

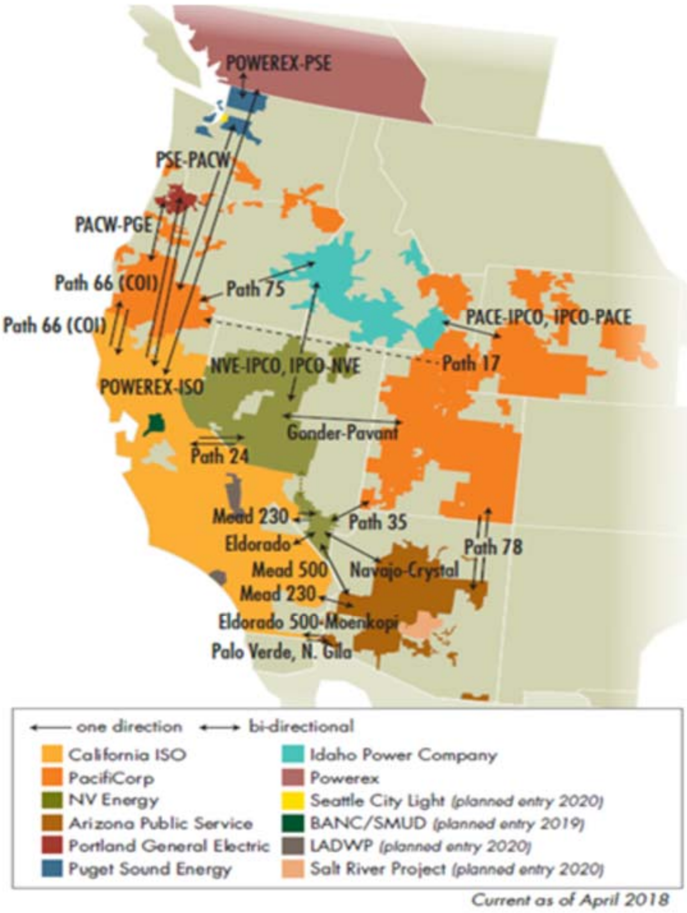
A. As described in my direct testimony, unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour, and there will be more efficient use of transmission with growing participation in the EIM. This was captured in the company's economic analysis by increasing the transfer capability between the east and west side of PacifiCorp's system by 300 MW. (Link Direct, lines 576–591.) Mr. Mullins states that this new transmission link does not exist today and testifies that PacifiCorp has no plans to build new transmission that would provide this increase in transfer capability. (Mullins Supplemental Rebuttal, lines 679–680.)

Mr. Mullins continues to misunderstand the incremental EIM transfer assumptions applied in the company's economic analysis. At no point has the company claimed that a new transmission line would be required to facilitate incremental intra-hour transfers between its east and west balancing authority areas. This incremental transfer capability results from intra-hour availability of unscheduled, unused, or re-optimized *existing* transmission. As more entities that have transmission connections with PacifiCorp's system join the EIM, there are increased opportunities to optimize these transmission assets within the hour. Despite Mr. Mullins's claims to the contrary, the EIM does in fact optimize the use of transmission assets of participating EIM entities within the hour. And this increased connectivity between PacifiCorp and other EIM entities currently enables additional transfers between the company's east and west balancing authority areas.

Figure 1-SR shows existing EIM entities and their transmission transfer capability. This figures shows a large amount of transfer capability between PacifiCorp's east balancing authority area Idaho Power, Nevada Energy, and Arizona Public Service Company. The transfer capability between Idaho Power and PacifiCorp's west balancing authority area is 1,500 MW (note, the transfer capability from PacifiCorp's east balancing authority area to Idaho Power is 2,557 MW).

PacifiCorp's EIM transfer assumptions are conservative in light of the total available transfer capability from PacifiCorp's east balancing authority area to its west balancing authority area through Idaho Power's system. Mr. Mullins's proposed adjustment for increased EIM transfers is based on a misunderstanding of the company's assumptions and should be rejected.

Figure 1-SR: Transfer Capability of Existing EIM Entities



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400* **
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <-> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <-> PSE	150
Powerex <-> ISO	150

** Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.*

*** When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.*

Q. Mr. Mullins also recommends an adjustment based on his allegation that PacifiCorp's economic analysis has not taken into consideration declining market prices. (Mullins Supplemental Rebuttal, lines 534–542.) And Mr. Peaco continues to believe the company's natural gas price assumptions are overstated. (Peaco Supplemental Rebuttal and Surrebuttal, lines 1222–1230.) Do you agree with these allegations?

A. No. Mr. Mullins correctly notes that PacifiCorp's December 2017 official forward price curve ("OFPC") reflects 72 months of market forwards followed by 12 months of a forwards-fundamental blend that transitions to a pure fundamentals-based forecast in month 85. Consequently, the first seven years of the December 2017 OFPC reflects or is influenced by observed market forwards as of December 29, 2017. This was the most current OFPC available at the time the company was finalizing its 2017R RFP bid evaluation and selection process and is representative of current market conditions.

Q. How is PacifiCorp's long-term natural gas price formulated?

A. PacifiCorp's natural gas price forecast reflects projections from an expert third-party forecasting service. The company subscribes to two expert third-party forecasting services to receive multi-client "off-the-shelf" natural gas-price forecasts, with supporting data, on a regular basis. Both forecasting services employ experts that perform energy market research and analytics to support hundreds of clients.

PacifiCorp's base case (medium) forecast provided by one of these third-party forecasting services is a moderate and reasonable long-term view supported by market research, analytics, and market fundamentals, as we know them today. Consequently, PacifiCorp's base case OFPC reflects observed forward market prices and a balanced, mainstream view of longer-term price projections.

Q. In their criticisms of PacifiCorp's market-price assumptions, do Mr. Mullins or any of the other parties address the material drivers for their expectations regarding long-term market prices?

A. No. Their analysis is based on past trends without addressing the likely drivers of price change.

Q. Can natural gas prices keep going down?

A. Not forever. For a decade now, natural gas prices have continued to reflect the effects of technological progress and increased producer efficiencies in expanding the resource base while lowering break-even costs. Between Appalachia and associated gas, supply is expected to outpace demand for the next five to six years, but diminishing returns (and as a corollary rising costs) will not be outpaced by technological progress and producer efficiencies forever. Drilling efficiency improvements continue but at a slower pace than in prior years and increased demands will require more expensive take-away capacity to be built out of Appalachia and the Permian. Thus, price appreciation is expected to take hold around the 2024-2025 time frame. Moreover, Appalachia and associated gas volumes (the lowest cost supplies) are expected to flatten after 2024, which is when liquefied natural gas ("LNG") exports and power sector demands are expected to accelerate.

Also, as noted by Ms. Kelly, "prices are closer to a floor than to a ceiling… the risk of lower and higher gas prices is asymmetrical. If gas prices are predicted to be $3.00, they can only be, at most, $3.00 too high. On the other hand, the upside of the equation is boundless. Prices in the past have reached $12.00 or more." (Kelly Response, lines 291–305.) Trends typically bottom-out and eventually end. Expert forecasts, based on comprehensive research and fundamentals-based market analysis account for changes in market dynamics that are not captured by evaluating past price trends.

Q. Why is demand for natural gas expected to grow in the 2024-2025 time frame?

PacifiCorp's nominal Henry Hub price forecast does not exceed $4.00/MMBtu until 2025 (2034 in 2016 dollars). Natural gas markets have historically been local due to transportation constraints, but the liquefaction of natural gas has linked domestic supplies to the global market, and this linkage will increase with growing LNG exports. Significant growth in LNG demand is coming from Asia, Europe, South America, and

Mexico. Moreover, piped exports into Mexico are expected to grow by 2025. In just a few years, U.S. LNG exports have gone from zero to six billion-cubic-feet ("BCF") per day, and U.S. LNG exports are expected to rise to between nine and 12 BCF per day by 2025.

Q. Mr. Mullins goes on to explain that the company relies on a third-party forecast from November 21, 2017, and is concerned that the December 2017 OFPC does not consider the effects of tax reform. (Mullins Supplemental Rebuttal, lines 557–565.) How do you respond?

A. As noted above, the OFPC reflects or is influenced by observed market prices through the first seven years (through 2024). The December 2017 OFPC that the company used in its medium price-policy scenarios reflects market forwards as of December 29, 2017, which is *after* President Trump signed the tax reform bill. This means that through the first seven years of the December 2017 OFPC, observed prices account for tax reform. Moreover, I have reviewed observed forward prices, which are updated each trading day, throughout December 2017, and there is no indication that there was any material change in forward prices that coincided with the timing of when tax reform legislation was passed by Congress and subsequently signed by President Trump. Consequently, I would not expect a material change in forecasted prices beyond the first seven years of the December 2017 OFPC.

Q. Did Mr. Mullins present all of the natural gas price forecasts he received from the company through discovery in Confidential Figure 3 of his supplemental rebuttal testimony?

A. No. PacifiCorp also provided an update to the November 2017 natural gas price forecast that was used in the company’s December 2017 OFPC. This updated forecast was issued on February 18, 2018 and is actually slightly *higher* than the November 2017 forecast used in the company's economic analysis. However, Mr. Mullins chose to omit this forecast in Confidential Figure 3 of his supplemental rebuttal testimony.

Q. Mr. Mullins testifies that market prices are declining, and he estimates that if a more recent price forecast were used, net benefits projected in the company’s economic analysis would decline. (Mullins Supplemental Rebuttal, lines 580–593.) How do you respond?

A. I am not surprised that net benefits from the Combined Projects would be reduced when applying a lower natural gas-price assumption—this is consistent with the company’s economic analysis which shows reduced benefits in low natural gas-price scenarios. As noted above, Mr. Mullins omitted from his analysis other, more current, third-party projections that are higher than those used in the company’s economic analysis. Had Mr. Mullins chosen to estimate how this forecast affects customer benefits, I would anticipate it would show increased benefits relative to the company’s base case analysis. Mr. Mullins is simply reconfirming that market price assumptions are a variable that will influence overall customer benefits from the Combined Projects.

While Mr. Mullins is entitled to his view of long-term market prices, I remain confident that PacifiCorp’s OFPC, which is based on observed market forwards and third-party forecasts supported by market research and informed by current market fundamentals, is the best and most likely forecast. This is the same forecast used to set customer rates and to establish avoided-cost prices for qualifying facilities. Nonetheless, even if market prices were to move, on a sustained basis, to those levels assumed by Mr. Mullins, the Combined Projects would still produce present-value net benefits for customers.

Q. Mr. Peaco claims that the "Combined Projects appear less likely to provide benefits to customers in the Low Gas scenarios and provide no meaningful improvement in the Medium and High Gas scenarios." (Peaco Supplemental Rebuttal and Surrebuttal, lines 666–668.) Do you agree?

A. No. Mr. Peaco's conclusion requires a wholesale rejection of PacifiCorp's economic analysis, which continues to show that customer benefits are highly likely. Contrary to Mr. Peaco's claims, customer benefits grow appreciably with higher natural gas price assumptions. Moreover, and as I stated earlier, the company's economic analysis is conservative. Mr. Peaco's assertion that benefits in the company's 20-year economic analysis are inflated due to the nominal treatment of PTCs, which was necessary to select among wind bids offered under different commercial structures in the 2017R RFP, is refuted in my testimony above.

Q. Mr. Peaco calculates a cost-benefit ratio of the Combined Projects across the nine price-policy scenarios in Table 1 of his supplemental rebuttal testimony and concludes that there are limited benefits relative to costs. (Peaco Surrebuttal, lines 443–473.) How do you respond?

A. Mr. Peaco calculates a simplified cost-benefit ratio in which a cost-benefit ratio greater than one indicates that benefits exceed costs, and a cost-benefit ratio less than one indicates that costs exceed benefits. In the medium natural gas, medium CO_2 price-policy scenario, the most likely outcome, Mr. Peaco's high-level analysis shows a positive cost-benefit ratio. Only in the low natural gas, zero CO_2 price-policy scenario, a scenario that Mr. Peaco has clarified is not the most likely scenario, and low natural gas, medium CO_2 price-policy scenario, are Mr. Peaco's cost-benefit ratios less than one.

Q. What conclusions do you draw from Mr. Peaco's cost-benefit analysis?

A. Mr. Peaco's cost-benefit analysis validates that PacifiCorp's economic analysis is reasonable. Consistent with my findings, Mr. Peaco's independent and high-level cost-benefit analysis shows net customer benefits in seven of nine price-policy scenarios, and that upside benefits outweigh downside risks. And despite Mr. Peaco's claims that the company's analysis overstates customer benefits, the company's economic analysis is conservative, because it does not account for potential Renewable Energy Credits ("REC") revenues, O&M cost savings, application of less conservative system benefit assumptions beyond 2036, an approximately 200 MW increase in transfer capability across the Aeolus-to-Bridger/Anticline transmission line, and application of Aeolus-to-Bridger/Anticline transmission costs in base case simulations without the proposed new wind projects. When averaged among all nine price policy scenarios, Mr. Peaco's cost-benefit ratios average over 1.092, meaning that on average, benefits outweigh costs by approximately 9.2 percent.

As noted above, in a previous request for approval of a voluntary resource decision filed by the company, DPU used this approach to evaluate the economics of the resource decision because, according to DPU's expert witness in that case, using the simple average of the price-policy scenario results produced a reasonable "risk-weighted benefit" that assumes each of the price-policy results is "equally likely." *In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval* *of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4*, Docket No. 12-035-92, DPU Exhibit 2.0 SR, lines 52–58 (Feb. 28, 2013). DPU's expert explained that using a simple average to produce a risk-weighted benefit was a "pretty good way" to do it because it was "neutral" and "doesn't attempt to say that lower gas prices are more likely or less likely in the future, just that they are equally likely with the base and high gas price forecasts." *In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4*, Docket No. 12-035-92, Transcript, page 165, lines 1–10 (Mar. 7, 2013).

Q. Mr. Peaco claims that his objections to the company's extrapolation methodology are unrefuted. (Peaco, Supplemental Rebuttal and Surrebuttal, lines 443–473.) Do you agree?

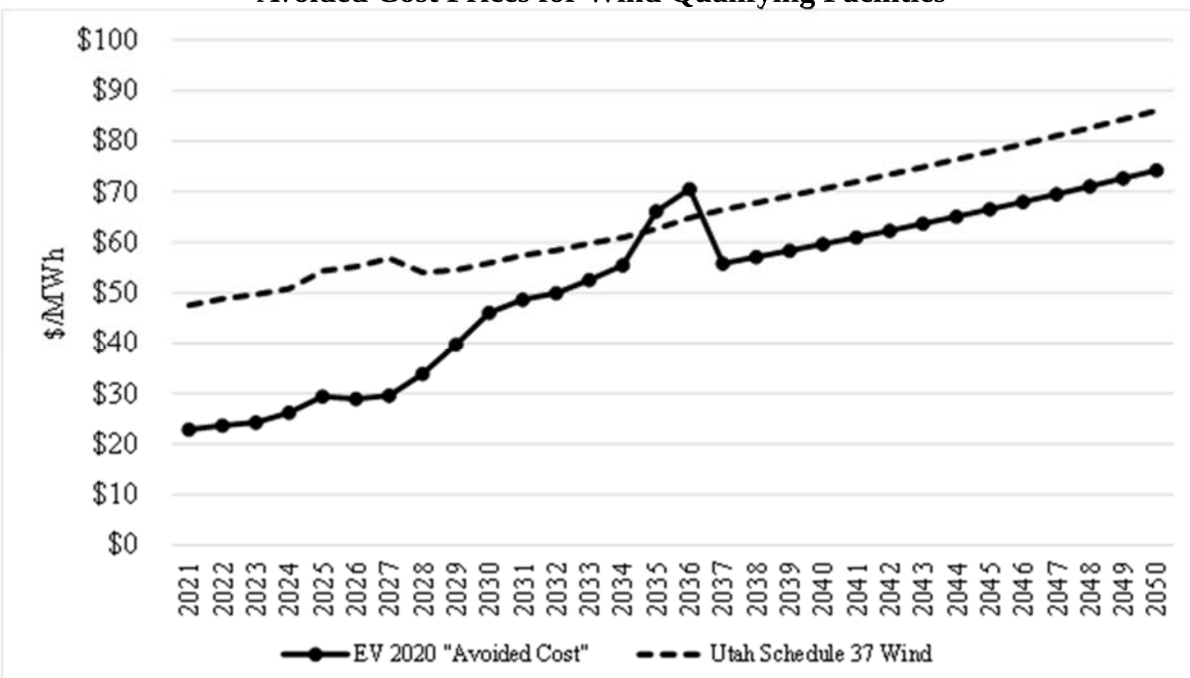
A. No. In my supplemental direct and rebuttal testimony, I responded to Mr. Peaco's criticisms, noting that he simply stated the company's results were problematic without adequately describing what those "problematic results" were. I also emphasized why the company's approach, which is based on a projection of how the Combined Projects are forecasted to affect system costs, is reasonable. (Link Supplemental Direct and Rebuttal, lines 1404–1416.) Mr. Peaco references specific examples of concerns he raised related to the company's extrapolation methodology in Docket No. 17-035-39. However, consistent with my supplemental direct and rebuttal testimony, he has not adequately identified the alleged anomalous results specific to the economic analysis in this proceeding that he states is the source of his concern. Further, in my second supplemental testimony, I explain why the company's extrapolated results are actually conservative when compared to the results observed from the models. (Link Second Supplemental Direct, lines 396–403.)

Q. In addition to comparing the extrapolated benefits to the benefits reported by the model in 2036, are there any other comparisons you can make that show the company's extrapolation approach is conservative?

A. Yes. PacifiCorp's economic analysis calculates the change in system costs between two model simulations—one with and one without the Combined Projects. This is precisely the same concept that is used to develop avoided cost prices for qualifying facility projects in Utah. Figure 2-SR compares the system benefits from the Combined Projects (without Uinta) on a dollar-per-MWh basis to the currently effective Utah Schedule 37 avoided-cost price for wind qualifying facilities. The currently effective avoided-cost price, which is meant to represent the value to PacifiCorp of purchasing energy and capacity from a wind qualifying facility, is available through 2036. Consistent with Utah Commission's order in Docket Nos. 17-035-T07 and 17-035-37, I extended the Utah Schedule 37 avoided cost price beyond 2036 at inflation so that it can be compared to the extrapolated system benefits used in the company's nominal revenue-requirement economic analysis.

The figure not only highlights my earlier point that the company's extrapolated benefits beyond 2036 do not reach the levels observed in the model in 2036 until about 2047, it also shows that the extrapolated benefits are significantly lower than the projected value of wind from a qualifying facility. In fact, the company's economic analysis also reflects estimated economic benefits that are also significantly lower than the Utah Schedule 37 avoided-cost price for wind in the near term. The levelized value of a Utah Schedule 37 wind facility over the 2021-2050 time frame is $59.12/MWh. Over this same period, the levelized value of the Combined Projects in the company's economic analysis is $42.69/MWh. If the Utah Schedule 37 avoided cost price for wind were used in lieu of the company's projected system benefits, the PVRR(d) benefits from the Combined Projects (without Uinta) in the medium case would increase from $174 million to $435 million when assessed through 2050.

Figure 2-SR: System Benefits Relative to Utah Schedule 37 Avoided Cost Prices for Wind Qualifying Facilities



Q. Mr. Mullins contends that there is a mismatch between nominal and levelized results, invalidating the 20-year study period analysis. He further states that the nominal study is a more straight-forward approach. (Mullins, Supplemental Rebuttal, lines 451–454.) Do you agree?

A. No. Both types of analysis—the system modeling results through 2036 and the nominal revenue requirement results through 2050—are useful in assessing the economics of the Combined Projects. The system modeling results provide a view of economic analysis that is consistent with the planning period and approach used to identify a least-cost, least-risk preferred portfolio in the IRP. This type of analysis was used to identify new wind and transmission projects as an element of PacifiCorp's least-cost, least-risk plan in the 2017 IRP and has been used to evaluate past resource acquisitions and plant investments. For instance, the same IRP models used to evaluate the Combined Projects in this proceeding, configured to simulate PacifiCorp's system over a 20-year time frame with the application of levelized capital costs, were used to support the company's acquisition of the Chehalis combined-cycle plant, support selection of the Lake Side 2 combined-cycle plant through an RFP process, and to support the company's application for approval for the installation of selective catalytic reduction equipment at Jim Bridger Unit 3 and Unit 4.

The nominal revenue requirement analysis provides a sense of how the Combined Projects might impact customer rates, relative to alternative resource procurement scenarios, over time. While an extension of system benefits associated with the Combined Projects through 2050 enables a PVRR(d) to be calculated, as with any long-term study, longer-term results are increasingly more difficult to project. Moreover, as noted above, I explained in my second supplemental direct testimony that the long-term extrapolation of system benefits used in the nominal revenue requirement analysis is conservative because the extrapolation approach yields projected benefits that do not reach the levels observed in the model in 2036 until 2047.

Q. Mr. Peaco claims that economic benefits from the Combined Projects have declined relative to Direct Testimony. (Peaco Supplemental Rebuttal, lines 610–654.) Do you agree?

A. No. Based on Mr. Peaco's own tables, customer benefits have increased in the majority of cases, and by greater margins than decreases in the remaining cases. For instance, in Table 3 of Mr. Peaco's rebuttal testimony, the 30-year expected case reports increased benefits of $30 million relative to the company's direct filing. It is not surprising that the updated nominal revenue requirement analysis, reflecting winning bids from the 2017R RFP and changes in federal tax law, produces a different net-benefit profile than what was shown in my original analysis, which reflected proxy wind resources and higher federal tax rates for corporations. Importantly, and as stated in my testimony, with reduced costs from the winning bids from the 2017R RFP, the Combined Projects generate substantial near-term benefits despite a reduction in PTC benefits associated with changes in federal tax law, and generate net benefits in 23 years out of the 30 years that the proposed owned-wind resources are assumed to operate.

Q. Mr. Peaco and Mr. Hayet disagree with application of a terminal value benefit in 2050, claiming that such a benefit is speculative and was not included in the original analysis. (Peaco Supplemental Rebuttal and Surrebuttal, lines 749–756; Hayet Second Rebuttal, lines 467–490.) How do you respond?

A. It is reasonable to include a terminal value benefit for projects where the company retains control of the site at the end of the asset life, and the company's analysis does not rely heavily on 2050 results to demonstrate a positive net benefit. Even if the terminal value were completely eliminated, which would not be appropriate, the

Combined Projects (without Uinta) would still produce $136 million in net customer benefits in the medium case before accounting for all of the conservative assumptions used in the company's economic analysis. In its initial filing, which relied upon proxy resources before the 2017R RFP was issued and when it was uncertain whether the company would own and operate winning bids, the company's economic analysis conservatively did not account for terminal value. However, the 2017R RFP specifically identified that terminal value would be considered during the bid evaluation and selection process, and once the winning bids were identified, these benefits, where applicable, were included in the company's economic analysis.

Q. Mr. Peaco suggests that terminal value benefits should be removed when calculating his alternative net benefits estimates. (Peaco Supplemental Rebuttal and Surrebuttal, lines 811–823.) How do you respond?

A. In Table 6 of Mr. Peaco's rebuttal testimony, he eliminates terminal value benefits. In making this adjustment, Mr. Peaco assumes that interconnection transmission assets, land rights, development rights, and other assets that have lives that extend beyond the assumed 30-year life of a wind facility, including retained access to a high-quality wind resource, will have no value. This is inappropriate, and his adjustment should be rejected.

Q. Mr. Mullins challenges the terminal value used in the company's economic analysis and suggests that transmission costs beyond 2050 should be included in the nominal revenue requirement analysis. (Mullins Supplemental Rebuttal, lines 475–493.) Mr. Peaco similarly recommends adjustments to add transmission costs beyond 2050. (Peaco Supplemental Rebuttal and Surrebuttal, lines 811–823.) Do you agree?

A. No. While Mr. Mullins does not challenge the magnitude of terminal values associated with the new wind projects, and does "not necessarily disagree" that utility-owned resources provide a terminal value that PPAs do not, he argues that, with regard to the transmission project, the company needed to also consider the ongoing capital maintenance and investment required to achieve the terminal value assumed in the economic analysis.

PacifiCorp's analysis recognizes that the useful life of the transmission project extends more than 30 years beyond the useful life of the new wind projects. Mr. Mullins and Mr. Peaco are correct that costs of the transmission project are not included beyond 2036 in the system modeling, nor are they included beyond 2050 in the nominal revenue requirement analyses. However, as noted in my testimony above, the company also did not include any incremental benefits of the proposed transmission project beyond 2036 in the levelized view, or beyond 2050 in the nominal view.

Q. Why did the company include a terminal value benefit for utility-owned resources?

A. The terminal value benefit recognizes the fact that at the end of a utility-owned resource's life, there is residual value that accrues to customers. For a PPA, the terminal value accrues to the project owner, not customers. That terminal value includes the facilities supporting the resources, like transmission facilities, that have longer useful lives and, in the case of generation tied to natural resources such as wind resources, there is inherent value in the site itself—particularly resources located in high-capacity-factor geographic areas like eastern Wyoming. These high-value renewable-resource locations are often scarce or unique in their suitability for generation permitting and construction, as well as proximity to transmission.

Q. Mr. Hayet asserts that PacifiCorp's assessment of terminal value is speculative and based on the assumption that new generation is built at the same project sites (Hayet Second Rebuttal, lines 172–175, 467–490.) How do you respond?

A. Terminal value, as assessed and described by PacifiCorp, includes: development rights; transmission assets (*e.g.*, network upgrades); and non-transmission infrastructure (*e.g.*, roads). PacifiCorp's terminal value reflects the material difference in the end-of-life worth of owned assets relative to PPA structures, and it is reasonable to expect that reasonable infrastructure value is expected to remain once these wind facilities have reached the end of their operating life. As discussed below, the independent evaluators confirmed the reasonability of this position and the conservative values used by PacifiCorp.

Q. Did the independent evaluators comment on the inclusion of the terminal value benefit in the 2017R RFP modeling?

A. Yes. The Utah independent evaluator observed that the terminal value is typically equal to the net salvage value of the resource, but for wind resources there are additional "assets associated with the wind site, such as land, site characteristics and generation interconnection and transmission facilities" that may provide additional value. (Utah IE Report at 33.) The independent evaluator explained that the terminal value benefits reflected the depreciated value of assets that have not fully depreciated at the end of the assumed 30-year life for the wind facilities, such as transmission assets, and the appreciated value of other elements of the project that remain at the end of the 30-year life, such as development rights.

The Oregon independent evaluator also noted that the terminal value was included to account for the fact that the company would own the site at the end of the project's useful life. (Oregon IE Report at 15.)

Q. Did the independent evaluators comment on the size of the terminal value benefit?

A. Yes. The Utah independent evaluator noted that the terminal value was "relatively low." (Utah IE Report at 42.) Likewise, the Oregon independent evaluator found that the "terminal value adders were fairly small." (Oregon IE Report at 17.) Notably, both of the independent evaluators confirmed and validated the company's bid selection and evaluation process, and proposed no adjustment.

THE PROCESS HAS ALLOWED FOR ROBUST REVIEW OF THE COMBINED PROJECTS

Q. Dr. Zenger claims that the IRP results for the Combined Projects and repowering were not filed until five months after filing the 2017 IRP. (Zenger Supplemental Rebuttal and Surrebuttal, lines 179–185.) Is this accurate?

A. No. PacifiCorp filed its 2017 IRP on April 4, 2017, which included economic analysis of the Combined Projects and repowering. PacifiCorp made an informational filing on August 2, 2017, a little less than four months after filing the 2017 IRP, which provided an updated economic analysis supporting the wind repowering, new transmission, and new wind investments. This informational filing summarized the very economic analysis that was included in the company's June 30, 2017 application and presented in my direct testimony. This informational filing was made to ensure that all IRP stakeholders, including those stakeholders that are not participating in this proceeding, had access to the most current economic analysis supporting the wind repowering, new transmission, and new wind investments contained in the 2017 IRP preferred portfolio.

Dr. Zenger's claim that parties have not had an opportunity to provide meaningful input is contrary to the facts. In February 2017, PacifiCorp finalized its IRP analysis of the Combined Projects. The scope of the Combined Projects and the accompanying economic analysis was discussed at a public-input meeting held in early March 2017, before filing the 2017 IRP on April 4, 2017. Moreover, after the 2017 IRP was filed, and before the application for the Combined Projects was filed, PacifiCorp met with IRP stakeholders to discuss the Combined Projects. The meeting with DPU took place May 10, 2017. Parties have had ample opportunity to review the Combined Projects since the 2017 IRP was filed over one year ago and have been reviewing the robust economic analysis presented in this proceeding for nearly 11 months.

Q. Dr. Zenger states: "Rather than representing refinements of a well-vetted structure for forecasting the future, the most recent projections in this Combined Projects docket result from shifting assumptions and structures following each round of review by non-company parties." (Zenger Supplemental Rebuttal and Surrebuttal, lines 168–178.) How do you respond?

A. I disagree. PacifiCorp has appropriately updated its assumptions and projections to ensure that its economic analysis remains current and that the results of this analysis accurately reflect projected customer benefits. These updates were necessary to confirm that the Combined Projects will deliver customer benefits, despite changes to federal tax law and market forces that are beyond PacifiCorp's control. To facilitate the parties' review of PacifiCorp's filings, the company has been transparent, has thoroughly documented and explained its updated assumptions, and has provided extensive work papers that support all of the economic analyses presented in testimony and accompanying exhibits.

Q. Dr. Zenger also states that evolving project details and updates to costs and benefits indicate that the Combined Projects are "uncertain enough to suggest preapproval is not in the public interest." (Zenger Supplemental Rebuttal and Surrebuttal, lines 108–122, 127–141.) Do you agree?

A. Absolutely not. As noted above, PacifiCorp has necessarily updated assumptions and projections to ensure its economic analysis of the projects remains current. This included updates to cost-and-performance inputs to align with bids received in the 2017R RFP, updates to reflect changes in federal tax law, updates to reflect more current load forecast and market forecast data, and a more accurate representation of PTCs. Through every step of the process, the economic analysis has shown that the proposed new wind and transmission investments are most likely to provide substantial customer benefits. Contrary to Dr. Zenger's opinion, the facts in this case demonstrate that the net benefits of the Combined Projects have withstood significant stress testing, which has only confirmed that Combined Projects will lower customer costs and are in the public interest.

Q. Dr. Zenger asserts that the process, including the expedited RFP, "burdened" parties to this docket. (Zenger Supplemental Rebuttal and Surrebuttal, lines 195–199). How do you respond?

A. Dr. Zenger's assertion is inconsistent with the testimony of DPU's witness addressing the RFP—Mr. Peterson. Mr. Peterson acknowledged the expedited schedule, but states: "In spite of a compressed schedule, the process worked fairly well." (Peterson Supplemental Rebuttal and Surrebuttal, line 150.) Also, the parties have had almost 11 months to review the Company's proposal, which is considerably longer than the timeframe provided by Utah statute.

PARTIES OVERSTATE PROJECT RISKS

Q. Dr. Zenger states that natural gas and carbon prices may be lower than assumed in the medium gas, medium CO_2 price-policy scenario, thus leading to an overstatement of benefits. (Zenger Supplemental Rebuttal and Surrebuttal, lines 337–342.) How do you respond?

A. PacifiCorp's medium gas, medium CO_2 price-policy scenario is the most reasonable and the most likely scenario that reflects observed forward market trades through 2024. Moreover, and as already noted in my rebuttal testimony, the low natural gas price forecast assumed stagnant LNG exports. According to the U.S. Energy Information Administration's *Annual Energy Outlook 2018* ("AEO 2018"), published on February 6, 2018, the United States is now a net exporter of natural gas and its reference case shows increased LNG exports in the coming years as additional terminals come into service. These increased exports will put pressure on future natural gas prices, meaning that over the next 32 years (*i.e.*, until 2050), it is unlikely that natural gas prices will remain as low as the low case used here—and may actually be higher than current forecasting predicts. With natural gas prices already very low and future demands expected to ratchet up, market prices are likely to respond to upside pressures, especially over a 20-30 year period. Likewise, PacifiCorp's CO_2 assumptions are already modest and distant in implementation with the low case being zero, while the medium and high scenarios start at $4.49/ton in 2030 and $3.62/ton in 2026, respectively. Since the downside is bounded by zero, there is little room for meaningful CO_2 scenarios of a lesser magnitude than those assumed in PacifiCorp's economic analysis.

Q. Mr. Peaco clarifies that he has not testified that the low natural gas, zero CO_2 price-policy scenario is the most likely, but that his focus on this scenario is to establish an analytical basis for the "high likelihood of benefits" standard. (Peaco Supplemental Rebuttal and Surrebuttal, lines 306–322.) How do you respond?

A. Mr. Peaco asserts that the Commission should assess whether the Combined Projects are in the public interest by establishing a higher standard of review because he believes these projects are not needed and are being justified as an economic opportunity. As I stated earlier, the Company has never stated that the Combined Projects are not needed to reliably serve its customers. The Combined Projects provide an opportunity to meet the company's projected capacity deficit while delivering customer benefits. Consequently, I disagree with Mr. Peaco's argument that the Commission should review the Combined Projects under a higher standard.

My economic analysis has consistently shown that the Combined Projects are needed to reliably serve our customers and that these investments are *most likely* to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to retail customers in Utah. Despite the fact there is no need for the Commission to review these projects under a higher standard, my economic analysis shows that the Combined Projects also meet this higher standard and are *highly likely* to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to retail customers in Utah. This economic analysis shows that the Combined Projects are expected to deliver net customer benefits in 16 of 18 modeled scenarios (nine price-policy scenarios over two different time frames). And these findings are conservative for the following reasons:

- Since the company's economic analysis was completed, updated transmission studies discussed by Mr. Rick A. Vail show the expected increase in transfer capability associated with the Aeolus-to-Bridger/Anticline transmission line is 951 MW, which is nearly 27 percent higher than the 750 MW assumed in the economic analysis.

- The economic analysis does not reflect expected O&M cost savings associated with installation of larger wind turbines at the TB Flats I & II and Ekola Flats projects.

- The economic analysis assigns no incremental value to the RECs that will be generated from the Combined Projects.

- The extrapolation of system benefits beyond 2036 are conservative as they do not reach levels observed in the model in 2036 until at least 2047.

- As described earlier in my testimony, the economic analysis conservatively assumes a base case simulation without any costs for the Aeolus-to-Bridger/Anticline transmission line—if this line were included in the base case simulation without the Combined Projects, it would increase present-value customer benefits by hundreds of millions of dollars in all price-policy scenarios.

- Price-policy scenarios that include a CO_2 price assumption are conservative because PacifiCorp inadvertently applied these inputs in 2012 dollars instead of nominal dollars.

Q. Mr. Peaco argues that there are scenarios is which the company may be correct in terms of benefits and there are scenarios in which the company may be wrong, concluding that the company is therefore asking customers to assume risks of large costs without corresponding benefits. (Peaco Supplemental Rebuttal and Surrebuttal, lines 361–365.) How do you respond?

A. I agree that there are market and policy uncertainties, which is why PacifiCorp analyzed a range of price-policy scenarios. When accounting for these uncertainties, PacifiCorp's economic analysis shows that not only are the Combined Projects *most likely* to generate net customer benefits relative to other resource options, they are *highly likely* to generate net customer benefits relative to other resource alternatives. My conservative analysis shows that this resource strategy would only be higher cost in two of 18 price-policy scenarios (nine price-policy scenarios and two different time frames). Moreover, Mr. Peaco has now clarified that one of these two scenarios—the low natural gas, zero CO_2 price-policy scenario—is not the most likely outcome (Peaco Supplemental Rebuttal and Surrebuttal, lines 309–311.)

Q. Are market risks greater for the Combined Project than for other resource options?

A. No. Market risk is inherent in every resource option, and most particularly FOTs, which are subject to fluctuations in market conditions right up to the moment of transaction. The zero-fuel-cost energy from the Wind Projects will reduce customer exposure to market risk, not increase customer exposure to market risk.

Q. Dr. Zenger states that moving forward with the Combined Projects may close off future opportunities for other possibly economic alternative resources such as battery storage or plant closures. (Zenger Supplemental Rebuttal and Surrebuttal, lines 357–361.) Do you agree?

A. No. This is a speculative claim that is entirely unsupported. PacifiCorp has evaluated all available resource options, including battery storage, plant closures, and transmission, under a range of market conditions and the Combined Projects are the most likely to deliver customer benefits. As I discussed earlier, even after PacifiCorp accounts for the incremental capacity from the Combined Projects, it has a remaining capacity shortfall that will require new resources to reliably serve our customers over time. PacifiCorp will continue to evaluate through each IRP cycle the least-cost, least-risk combination of resources that can be used to meet these capacity needs prospectively. The Combined Projects will not preclude PacifiCorp from evaluating all future resource alternatives, accounting for changes in technologies, system conditions, and market developments.

Q. Mr. Peaco claims that because the company took issue with his characterization of risk, such as production risk associated with the Wind Projects, that it is an example of the company asking customers to assume significant risk. (Peaco Supplemental Rebuttal and Surrebuttal, lines 323–336.) Is this true?

A. No. As I stated in my supplemental direct and rebuttal testimony, Mr. Peaco's analysis is asymmetrical and ignores the possibility that wind production may also be higher than reasonably assumed in my economic analysis. Mr. Peaco's assertion is not based on fact or analysis that supports his claim that the company is asking customers to assume significant wind-production risks. Simply stated, Mr. Peaco has not explained why he believes the company's wind production estimates are not reasonable. In contrast, PacifiCorp has performed robust risk analysis of wind variability, including the retention of a third-party expert to verify the wind-production estimates for every bid selected to the initial shortlist in the 2017R RFP. Mr. Chad A. Teply also provided testimony explaining that the company's existing wind projects in the Medicine Bow area of Wyoming have out-performed pre-construction estimates.

Q. Is it your position that Mr. Peaco is overstating the P50-related wind variability risk?

A. Yes. Mr. Peaco's characterization of the P50 assessment and curtailment probability is extreme, and does not seem to consider principles of probability and outcome. The P50 assessment simply says that there is an equal probability of actual generation being higher or lower than the forecasted value. This does not mean that the company's wind shapes have a 50-percent chance of being completely wrong; it means rather that over time, statistics favor actual generation being high just as often as it is low, resulting in a long-term shape that closely matches the P50 shape. The reduction in P50 energy that Mr. Peaco refers to would therefore have to be a sustained and improbable reduction in wind generation, potentially lasting decades, and without offsetting seasonal or annual increases in wind.

Q. Does Mr. Peaco dispute the equally likely potential upside benefits related to wind variability?

A. No. While he mentions my earlier response to his unsupported criticisms of the company's wind-production estimates, he does not dispute it, and in fairness, I would assume he is concerned only with the potential for negative impacts to customers. To clarify my position, I do not believe that huge upside benefits will materialize any more than I believe Mr. Peaco's huge downside costs will occur. My point is only that the P50 wind shape is a carefully vetted and reasonable estimate, and that inevitable variations that occur will be offsetting over the long term.

Q. How has the level of risk for the Combined Projects changed since the initial filing?

A. While it is true that some changes have reduced customer benefits, decreases have been more than offset by other factors, such as lower installed capacity costs associated with the Wind Projects, which as I described earlier are down [redacted] percent relative to the cost for owned resources included in the company's initial filing.

Also, risks have been reduced because we now know much more about significant drivers of costs and benefits. For instance, when the company made its initial filing, it was uncertain whether federal tax-reform legislation would be introduced and how that legislation might impact PTC benefits, which are important to the economic benefits of the Combined Projects. Similarly, at that time, the company had not yet issued the 2017R RFP and had not received firm pricing for wind resource bids solicited through a competitive bidding process. At this time, these uncertainties have been eliminated and replaced with known tax-law changes and firm, competitive wind-resource pricing, and the updated economic analysis of the Combined Projects continues to demonstrate that these investments will generate substantial customer benefits. In total, when all of the changes are considered, and considering how much more we now know about tax policy and costs, the company's analysis shows that risks have decreased and customer benefits have increased since the initial filing.

Q. Dr. Zenger expresses concerns over changes to capital costs and argues that such large shifts can overwhelm benefits. (Zenger Supplemental Rebuttal and Surrebuttal, lines 238–247.) How do you respond?

A. Mr. Chad A. Teply rebuts the basis for Dr. Zenger's concerns over changes to capital costs, which have no bearing on whether actual costs will be higher or lower than current estimates. In fact, as stated above, the capital cost of owned wind facilities on a per-kilowatt basis is down [redacted] percent from the estimates assumed in the company's initial filing. As explained in my supplemental direct and rebuttal testimony, the reduction in capital costs has mitigated the reduction in benefits from changes in the federal income tax rate applicable to corporations. Dr. Zenger's claim that the large shift in capital costs can overwhelm benefits ignores my testimony, which demonstrates that benefits increased when the Ekola Flats project displaced PacifiCorp's McFadden Ridge II benchmark project even though capital costs also increased.

Q. Several parties also point to the comments made by the Oregon independent evaluator related to his recommendation to the Oregon Commission that the company's bids be subject to cost and performance guarantees to make the utility-owned resources comparable to PPAs. (*See, e.g.*, Peterson Supplemental Rebuttal and Surrebuttal, lines 289–311; Hayet Second Rebuttal, lines 999–1007.) How do you respond to the Oregon independent evaluator's recommendations?

A. As the Chair of the Oregon Commission pointed out during an April 30, 2018 special public meeting on the 2017R RFP final shortlist, the Oregon independent evaluator went beyond the scope of his responsibilities in opining on ratemaking considerations. The Chair highlighted that determining the future ratemaking treatment of the Wind Projects was the Oregon Commission's responsibility (not the independent evaluator's).

In addition, similar to the parties' positions in this case, the Oregon independent evaluator's ratemaking conditions were premised on the theory that there is no need for the Wind Projects. Because there is a clear need, the ratemaking conditions are irrelevant.

Q. Are all of the project risks raised by parties asymmetrical, meaning they would only harm customer interests?

A. No. The risks that parties have identified are really best characterized as uncertainties, and these uncertainties do not just provide downside risk for customers. These uncertainties also provide opportunities to improve customer benefits beyond what is assumed in PacifiCorp's economic analysis. Project performance can be better than expected, as Mr. Chad A. Teply indicates has occurred. Capital costs can be lower than expected, as Mr. Vail indicates has occurred. Ongoing O&M costs can be less than expected, which is likely given the conservative assumptions used in the company's economic analysis. Price and policy changes may increase the net benefits from the Combined Projects.

It is also important to recognize that the winning bids selected to the 2017R RFP final shortlist are based on firm-pricing proposals through a competitive solicitation process with oversight from two independent evaluators. The company also provided evidence that its prior two large-scale transmission projects were 19 percent and six percent under budget.

Q. How has PacifiCorp's ongoing analysis contributed to the assessment of risk?

A. PacifiCorp's economic analysis in this docket has been thorough and extensive. The updated economic analysis summarized in my second supplemental direct testimony alone includes 26 SO model simulations and 26 PaR simulations. Each PaR simulation considers 50 different iterations of system performance with variations in stochastic variables, which includes variations in load. Accounting for the stochastic system simulations performed using PaR, the economic analysis summarized in my second supplemental direct testimony represents over 1,300 simulations of PacifiCorp's system over a 20-year forecast time frame. Through these studies, the company has assessed how the net benefits of the new wind and transmission projects are affected by the proposed wind repowering project, solar resource opportunities, selection of alternative wind-turbine equipment, alternative natural gas price assumptions, alternative CO_2 price assumptions, and application of alternative assumptions for O&M cost and REC revenues.

SOLAR RESOURCE SENSITIVITY

Q. Please summarize the solar resource sensitivity provided in your previous testimony.

A. My supplemental direct testimony provided robust modeling results through 2036 using the SO model and PaR based on preliminary bid analysis from the 2017S RFP. Those modeling results supported two important conclusions.

First, solar PPAs provided fewer benefits than the Combined Projects under the medium natural gas, medium CO_2 price-policy scenario, and slightly fewer benefits under the low natural gas, zero CO_2 price-policy scenario using PaR, and slightly more benefits under the low natural gas, zero CO_2 price-policy scenario using the SO model. In other words, under the medium natural gas, medium CO_2 price-policy scenario, the Combined Projects are superior, and under the low natural gas, zero CO_2 price-policy scenario the Combined Projects are roughly equal to the solar PPAs.

Second, when analyzed together, the Combined Projects and solar PPAs produced greater customer benefits under both the medium natural gas, medium CO_2 price-policy scenario and low natural gas, zero CO_2 price-policy scenario relative to scenarios where either the Combined Projects or solar PPAs are procured on their own.

Significantly, none of wind or solar bids were hard-coded into the model, and when solar bids were selected in the models, they did not displace the wind bids. These conclusions indicated that it is not a question of whether the company should pursue the Combined Project *or* the solar PPAs, but rather a question of whether the company should pursue the Combined Projects *and* the solar PPAs.

Q. Did the company provide the solar sensitivity to the independent evaluators who monitored the 2017R RFP?

A. Yes. The Oregon independent evaluator noted in his report: “In all cases the combination of solar and shortlisted [wind] resources provided more net benefits.” (Oregon IE Report at 36.) Although the Utah independent evaluator did not specifically comment on the solar sensitivity, he did not challenge it in his final report. (*see* Utah IE Report at 61.)

Q. Mr. Mullins argues that the solar sensitivity studies showed that the final bids received in the 2017S RFP were lower cost and lower risk than the Combined Projects. (Mullins Supplemental Rebuttal, lines 368–370.) Do you agree?

A. No. PacifiCorp has now completed its bid evaluation and selection process for the 2017S RFP, and the complete analysis and results confirm the company's earlier assessment that solar PPA bids do not displace the economic benefits of the Combined Project. While the base economic analyses of solar bids show that there are potential customer benefits associated with a 1,320 MW portfolio of solar PPAs from the 2017S RFP, subsequent sensitivity analyses show a risk, unique to solar resource opportunities, that the projected benefits for the solar PPAs in the base economic analysis are overstated, as I will discuss below.

In addition, driven by uncertainties regarding tariff and tax reforms, current solar resource pricing likely reflects a risk premium, and solar project costs are expected to decline. Because the 30-percent ITC is available for solar resources that come online by 2021, PacifiCorp expects that solar pricing received in late 2019 for projects that could come online in 2021 will be lower than pricing received in the 2017S RFP and would avoid the current risk premium associated with the tariff and tax reform uncertainties. Thus, PacifiCorp does not need to act now and has decided not to select any of the 2017S RFP bids to the final shortlist.

PacifiCorp will continue to assess potential economic benefits from solar resource opportunities in the 2019 IRP and through bi-lateral discussions with developers, including a thorough evaluation of hourly price-profile and capacity-contribution risks (discussed below) with full stakeholder engagement and a more orderly assessment of the potential customer benefits of solar generation. Should subsequent analysis in the 2019 IRP demonstrate that solar resource opportunities provide economic benefits for customers, or if there is an opportunity to mitigate evaluation risks, there will be sufficient time to initiate a new competitive solicitation process or to pursue bi-lateral contracts for projects capable of achieving commercial operation by the end of 2021 that can qualify for the 30-percent ITC. This potential solicitation could consider storage bids as a means to mitigate valuation risks and allow sufficient time for participants to be further along in the transmission interconnection process.

Q. Did PacifiCorp inform the independent evaluator overseeing the 2017S RFP of its final shortlist results?

A. Yes. PacifiCorp summarized its 2017S RFP final shortlist bid evaluation and selection analysis with London Economics International, LLC, the independent evaluator retained by the company to monitor the 2017S RFP, on March 12, 2018. This summary is included in the final report of the independent evaluator for the 2017S RFP, which is provided as Exhibit RMP__(RTL-3SR) ("Solar IE Report").

Q. Did the independent evaluator for the 2017S RFP agree with the company's conclusions?

A. Yes. The independent evaluator concluded that the company's decision to not accept any solar bids was not unreasonable and that PacifiCorp's concerns over conditions in the solar market that reflected uncertainties over tax reform and tariffs were reasonable. In addition, the independent evaluator concluded that the 2017S RFP was conducted in a manner that was consistent with general procurement best practices, unbiased, that the selection of the shortlisted resources was fair, and that the company's modeling reflected industry best practices. (Solar IE Report at 4–5.)

Q. What additional sensitivity analyses did PacifiCorp perform in the 2017S RFP to better assess the potential customer benefits and valuation risks associated with the solar resource bids?

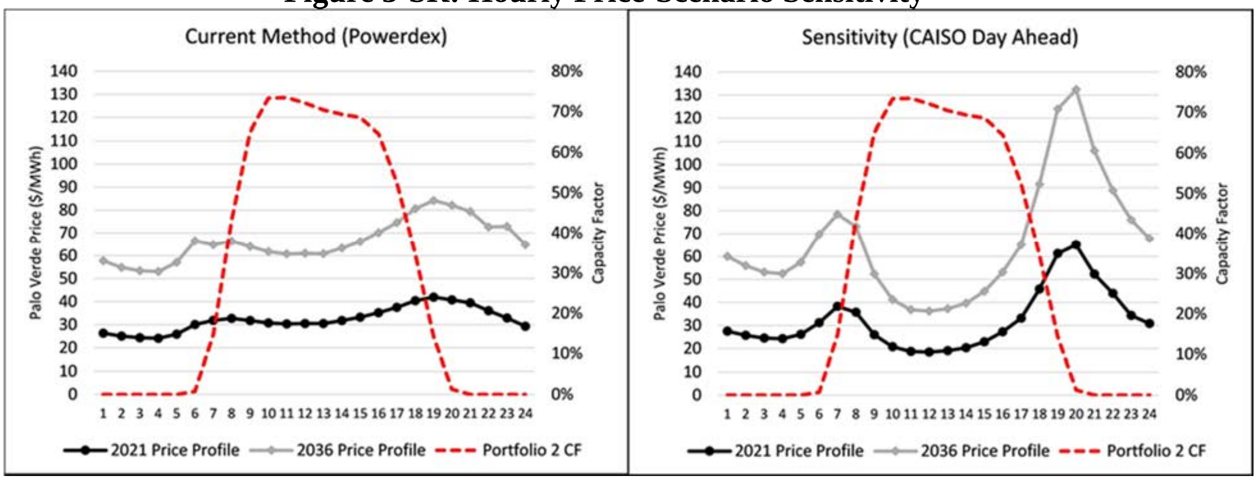
A. PacifiCorp performed two additional sensitivities. First, the company refined how it converts its forward market prices into hourly prices to more accurately reflect hourly market-price variation in those hours when solar resources are producing energy. Second, the company performed a capacity-contribution sensitivity to assess how changes in the assumed ability of solar resource to meet peak load during periods when there is an increased probability of loss-of-load events affect the overall customer benefits.

Q. Please describe the hourly price-profile sensitivity developed to analyze bids in the 2017S RFP.

A. PacifiCorp uses hourly price scalars, which are applied to monthly on-peak and off-peak prices in the forward price curve, to derive hourly market price profiles that vary by month and day type (*i.e.*, weekdays, Saturdays, and Sundays/holidays). PacifiCorp currently uses five years of hourly Powerdex price data to develop price scalars. The company's review of the Powerdex data shows that the five-year price history is not supported by a significant volume of reported transactions (many hours have no market pricing inputs) and that the resulting hourly price shapes do not align with prices observed in operations that are being increasingly influenced by growth in solar resources across the region. Thus, for the hourly price-profile sensitivity, PacifiCorp developed an alternative set of price scalars that are derived from one year of day-ahead hourly prices available from the California Independent System Operator ("CAISO").

The figure below illustrates the differences between the Powerdex-derived scalars and the CAISO-derived scalars.

Figure 3-SR: Hourly Price-Scenario Sensitivity



The figure at top left shows representative average hourly price profiles as derived from historical Powerdex data and used in the bid-evaluation process of the 2017S RFP. The figure at top right shows representative average hourly price profiles derived from historical CAISO data and used in this sensitivity. In both figures, the hourly price profile is based on the average hourly prices from representative months (January, April, July, and October) and shown alongside the average hourly energy profile of bids included in a solar-PPA bid portfolio. The price profile used in the sensitivity shows that, when accounting for the growth of solar resources across the region, prices are lower during those hours when the resources in the solar-PPA bid portfolio are expected to generate electricity.

Q. Does the company intend to use the CAISO-derived scalars in future resource analyses?

A. Yes. The company used the refined scalars in the 2017 IRP Update and intends to continue using the refined scalars in future IRPs and future regulatory filings.

Q. How do the refined hourly price scalars impact the benefits of the solar-PPA resources?

A. The use of the CAISO-derived hourly price scalars decreased the benefits of the solar PPAs. This outcome was observed regardless of whether these price scalars were applied to studies evaluating solar-PPA bids with or without the Combined Projects. When analyzed in isolation from the Combined Projects, 20-year PaR studies (through 2036) show that application of the CAISO-derived hourly price scalars decreased solar-PPA benefits from \$174 million to \$108 million (a reduction of \$66 million) based on stochastic-mean PaR results and from \$183 million to \$114 million (a reduction of \$69 million) based on risk-adjusted PaR results in the medium natural gas, medium CO_2 price-policy scenario.

When analyzed under the low natural gas, zero CO_2 price-policy scenario, the CAISO-derived hourly price scalars decreased the benefit of the solar PPAs from showing a \$45 million net benefit to showing a \$10 million net cost (a \$55 million reduction in benefits) based on stochastic-mean PaR results and from showing a \$48 million net benefit to showing a \$10 million net cost (a \$58 million reduction in benefits) based on risk-adjusted PaR results.

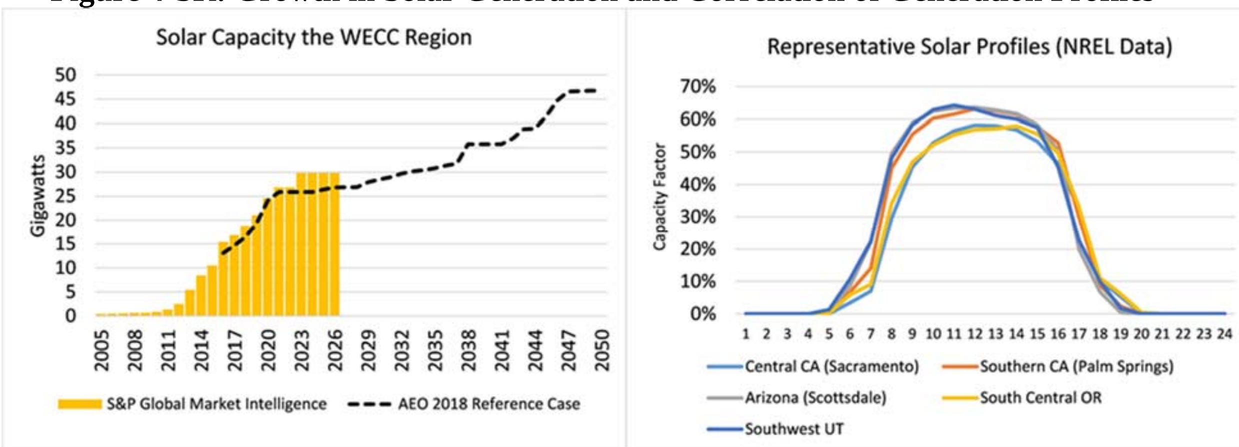
The price-policy scenario assumptions used to analyze solar-PPA bids in the 2017S RFP are identical to those used to analyze the Combined Projects in my second supplemental direct testimony, with the exception that the medium CO_2 price assumptions were correctly applied as a nominal cost instead of real costs in 2012 dollars.

Q. Are there any other issues to consider related to the price-profile used to evaluate the solar-PPA bids?

A. Yes. The expected increase in solar generation, coupled with correlation among expected solar resource generation profiles across the west, has had a significant impact on hourly prices and will continued to do so as solar development increases. S&P Global Market Intelligence tracks power-plant capacity, and reports that solar capacity in the Western Electricity Coordinating Council ("WECC") region, which represents capacity that is online or announced to go online having obtained regulatory approvals, will grow from 16.8 gigawatts ("GW") in 2017 to 29.8 GW by 2023 (growth of approximately 77 percent over six years). Similarly, the AEO 2018 Reference Case trends closely with the S&P Global Market Intelligence data, and shows continued growth of solar capacity in the WECC, which reaches 46.8 GW by 2050. By the end of a 25-year solar PPA (2045), the AEO 2018 Reference Case predicts that solar capacity in the WECC region will grow to 41.3 GW, which is 2.5 times the amount of solar capacity reported for 2017.

The rapid increase in solar capacity across the region over the past five years has significantly impacted hourly market prices, and continued growth in new solar capacity could further affect the market value of solar energy beyond what has been analyzed in the price-profile sensitivity described above. Moreover, proxy solar profiles from the National Renewable Energy Laboratory ("NREL") show a high degree of correlation among potential solar sites across the WECC region, indicating that the potential impacts on hourly price profiles are likely regardless of where new solar is added. The figure below illustrates the expected growth in solar generation and the correlated generation profiles throughout the region.

Figure 4-SR: Growth in Solar Generation and Correlation of Generation Profiles



Q. Did the independent evaluator for the 2017S RFP comment on the hourly price sensitivity?

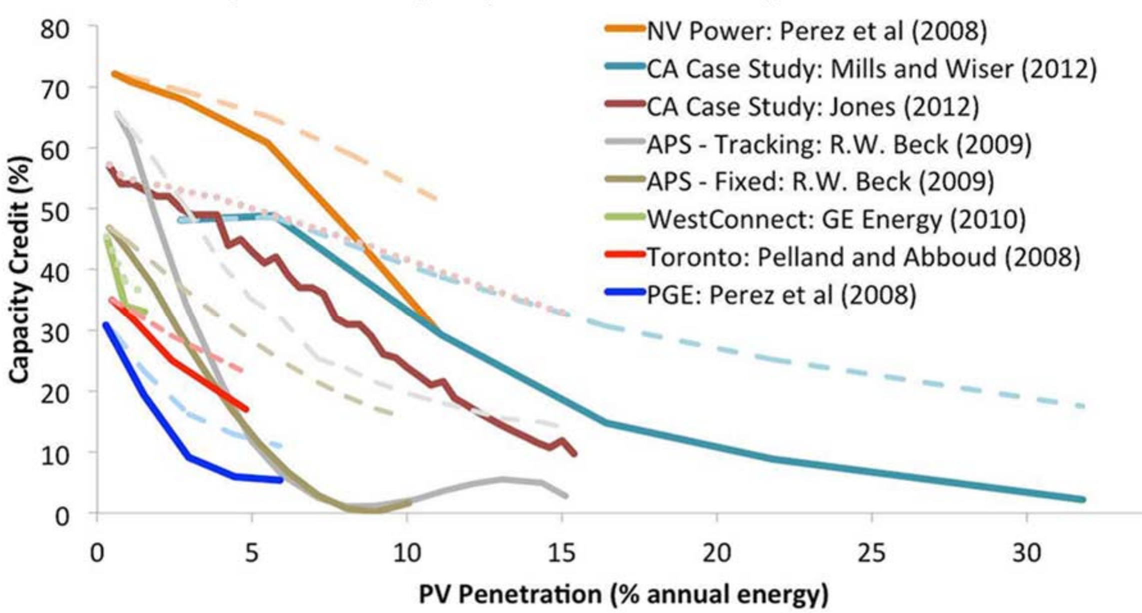
A. Yes. The independent evaluator concluded that the "alternative price profile was a reasonable way to examine potential downside risks to customers of committing to solar resources." (Solar IE Report at 25.)

Q. Please describe the capacity-contribution sensitivity used in the 2017S RFP bid evaluation and selection process.

A. The capacity-contribution sensitivity is designed to assess the risks associated with overstating the capacity contribution of solar resources when evaluating the potential customer benefits of solar PPA bids. The capacity contribution of solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. The company's base economic analysis used to evaluate bids submitted into the 2017S RFP and used to support the solar sensitivity studies in my supplemental direct and second supplemental direct testimony applied the capacity-contribution values for solar resources developed for the 2017 IRP (59.7 percent for the solar PPAs located in Utah), and therefore the base economic analysis assumes that the 1,320 MW of solar-PPA capacity included in the 2017S RFP bid portfolio can displace the need for approximately 788 MW of system capacity (59.7 percent multiplied by the 1,320 MW of solar-PPA capacity).

As more highly correlated solar generation is added to the system, the energy output from these resources is more likely to shift the timing of potential loss-of-load events to evening hours when solar irradiance is low and generation levels are greatly reduced or zero. Consequently, solar capacity-contribution values are highly sensitive to increasing solar penetration levels. The figure below illustrates study results concluding that additional solar generation reduces the capacity contribution of solar resources.

Figure 5-SR: Capacity Contribution Compared to Penetration



Source: Mills, Andrew, and Ryan Wiser. 2012. "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes." LBNL-5933E, Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory.

For PacifiCorp, the addition of 1,320 MW of solar capacity would more than double the amount of solar resources on its system. The capacity-contribution sensitivity evaluates the economic impact of halving the capacity-contribution value from 59.7 percent to 29.9 percent when applying medium natural gas, medium CO_2 and low natural gas, zero CO_2 price-policy assumptions. Considering that the company will begin using the hourly price profiles derived from day-ahead CAISO data in the 2017 IRP Update, future IRPs, and future regulatory filings, the capacity-contribution sensitivity also includes the CAISO-derived hourly price profile.

Q. What were the results of this capacity-contribution sensitivity used to evaluate bids in the 2017S RFP?

A. With the capacity-contribution assumption reduced from 59.7 percent down to 29.9 percent, the amount of system capacity that the 1,320 MW of solar resource capacity can displace is reduced from 788 MW to 394 MW. This reduces the resource-deferral value of the solar-PPA resources, which in turn reduces the net benefits of the solar-PPA bids.

The combined effect of the hourly price-profile and capacity-contribution assumptions, when solar-PPA bids are analyzed in isolation of the Combined Projects over a 20-year time frame in PaR, is to decrease the solar-PPA benefits from $174 million to $69 million (a reduction of $105 million in benefits) based on stochastic-mean PaR results, and from $183 million to $73 million (a reduction of $110 million in benefits) based on risk-adjusted PaR results in the medium natural gas, medium CO_2 price-policy scenario.

When analyzed under the low natural gas, zero CO_2 price-policy scenario, the combined effect of the hourly price-profile and capacity-contribution assumptions is to decrease the benefit of the solar PPAs from showing a $45 million net benefit to showing a $56 million net cost (a $101 million reduction in benefits) based on stochastic-mean PaR results, and from showing a $48 million net benefit to showing a $58 million net cost (a $106 million reduction in benefits) based on risk-adjusted PaR results.

Again, the price-policy scenario assumptions used to analyze solar-PPA bids in the 2017S RFP are identical to those used to analyze the Combined Projects in my second supplemental direct testimony, with the exception that the medium CO_2 price assumptions were correctly applied as a nominal cost instead of real costs in 2012 dollars.

Q. When assessing the impact of the hourly price-profile sensitivity for the 2017S RFP, did the company consider how the CAISO-derived hourly price scalars might affect the economic analysis of the Combined Projects?

A. Yes. The table below summarizes how the CAISO-derived hourly price-scalar assumptions impact the Combined Projects and, separately, how these assumptions impact the 1,320 MW bid portfolio that includes solar PPAs without the Combined Projects when applying medium natural gas, medium CO_2 price-policy assumptions.

Table 4-SR: Solar-Only Compared to Combined Projects
Hourly-Price Sensitivity System Modeling Results
(Medium Gas, Medium CO2)

	Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million	**Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million**
Combined Projects		
Benchmark Analysis (Second Supplemental Direct)	$(357)	$(386)
Hourly Price-Profile Sensitivity & Nominal CO_2	$(328)	$(343)
Decrease in Net Benefits	$29	$43
2017S Solar-PPA Bid Portfolio		
Benchmark Analysis (Current Hourly Scalars)	$(237)	$(248)
Hourly Price-Profile Sensitivity	$(160)	$(168)
Decrease in Net Benefits	$77	$80

This analysis shows that the new hourly prices-profile decreases the customer benefits of the Combined Projects on a stand-alone basis and decreases the customer benefits of the solar PPAs on a stand-alone basis. But, importantly, the reduction in net benefits associated with the hourly-price profile sensitivity is between 1.9 and 2.7 times greater for the solar PPAs than it is for the Combined Projects when applying medium gas, medium CO_2 price-policy assumptions. The disproportionate impact is consistent with the fact that solar generation profiles are more highly correlated with the impact solar resources are having on hourly price profiles relative to wind. While both types of technologies are faced with the same reduction in the market value of energy during the middle of the day, the wind generation produces energy during the early morning and late evening hours, when the market value of energy is higher.

Q. Did you conduct this same analysis for the low gas, zero CO_2 price-policy scenario?

A. Yes. The table below summarizes how the CAISO-derived hourly price-scalar assumptions impact the Combined Projects and the 1,320 MW solar-PPA bid portfolio when applying low gas, zero CO_2 price-policy assumptions.

Table 5-SR: Solar-Only Compared to Combined Projects
Hourly-Price Sensitivity System Modeling Results
(Low Gas, Zero CO_2)

	Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million	Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million
Combined Projects		
Benchmark Analysis (Second Supplemental Direct)	($150)	($156)
Hourly Price-Profile Sensitivity	($125)	($130)
Decrease in Net Benefits	$25	$26
2017S Solar-PPA Bid Portfolio		
Benchmark Analysis (Current Hourly Scalars)	($125)	($131)
Hourly Price-Profile Sensitivity	($69)	($72)
Decrease in Net Benefits	$56	$59

Similar to the medium gas, medium CO_2 price-policy scenario, the results show that the net benefits associated with both the Combined Projects and the solar PPAs decreased, but, again, the reduction in net benefits associated with the hourly-price profile sensitivity is approximately 2.2 to 2.3 times greater for the solar PPAs than it is for the Combined Projects when applying low gas, zero CO_2 price-policy assumptions.

Q. What conclusions can you draw from these results?

A. The solar PPAs are more sensitive to the refined hourly price-profile and therefore present a greater risk that the customer benefits of the solar PPAs are overstated relative to the Combined Projects.

Q. Did the company apply the capacity-contribution sensitivity to the Combined Projects?

A. No. Unlike solar resources, wind resources are expected to generate in all hours of the day, and thus the energy output from wind resources are not likely to shift the timing of potential loss-of-load events to hours when the wind is not generating. Consequently, the capacity-contribution value for wind resources (15.8 percent for east wind as reported in the 2017 IRP) is less likely to be materially impacted with increasing penetration of either new wind or solar resources.

Q. How do the economics of the Combined Projects with CAISO-derived hourly price scalars compare to the economics of the solar-PPA bid portfolio that reflects the combined effects of the alternative hourly-price and capacity-contribution assumptions?

A. The table below summarizes how these assumptions impact the Combined Projects and the 1,320 MW solar-PPA bid portfolio when applying medium natural gas, medium CO_2 price-policy assumptions.

Table 6-SR: Solar-Only Compared to Combined Projects Capacity-Contribution Sensitivity System Modeling Results (Medium Gas, Medium CO_2)

	Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million	Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million
Combined Projects		
Benchmark Analysis (Second Supplemental Direct)	($357)	($386)
Hourly Price-Profile Sensitivity & Nominal CO_2	($328)	($343)
Decrease in Net Benefits	$29	$43
2017S Solar-PPA Bid Portfolio		
Benchmark Analysis (Current Hourly Scalars/Cap Cont.)	($237)	($248)
Hourly Price-Profile/Cap Cont. Sensitivity	($93)	($97)
Decrease in Net Benefits	$144	$151

As set forth above, the combined effect of the hourly price-profile and capacity-contribution assumptions is to reduce the net benefits of the solar-PPA bids by between $144 million and $151 million in the medium gas, medium CO_2 price-policy scenario, which is approximately 3.5 to 5.0 times greater than the impact of the hourly price-profile on the Combined Projects.

Q. What do these sensitivities show when applying low gas, zero CO_2 price-policy assumptions?

A. The table below summarizes how hourly price-scalar and capacity-contribution sensitivity assumptions affect the Combined Projects and the 1,320 MW solar-PPA bid portfolio when applying low natural gas, zero CO_2 price-policy assumptions.

Table 7-SR: Solar-Only Compared to Combined Projects
Capacity-Contribution Sensitivity System Modeling Results
(Low Gas, Zero CO_2)

	Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million	**Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million**
Combined Projects		
Benchmark Analysis (Second Supplemental Direct)	($150)	($156)
Hourly Price-Profile Sensitivity	($125)	($130)
Decrease in Net Benefits	$25	$26
2017S Solar-PPA Bid Portfolio		
Benchmark Analysis (Current Hourly Scalars/Cap Cont.)	($125)	($131)
Hourly Price-Profile/Cap Cont. Sensitivity	($8)	($8)
Decrease in Net Benefits	$117	$123

The combined effect of the hourly price-profile and capacity-contribution assumptions is to reduce the net benefits of the solar-PPA bids by between $117 million and $123 million in the low natural gas, zero CO_2 price-policy scenario, which is approximately 4.7 times greater than the impact of the hourly price-profile on the Combined Projects.

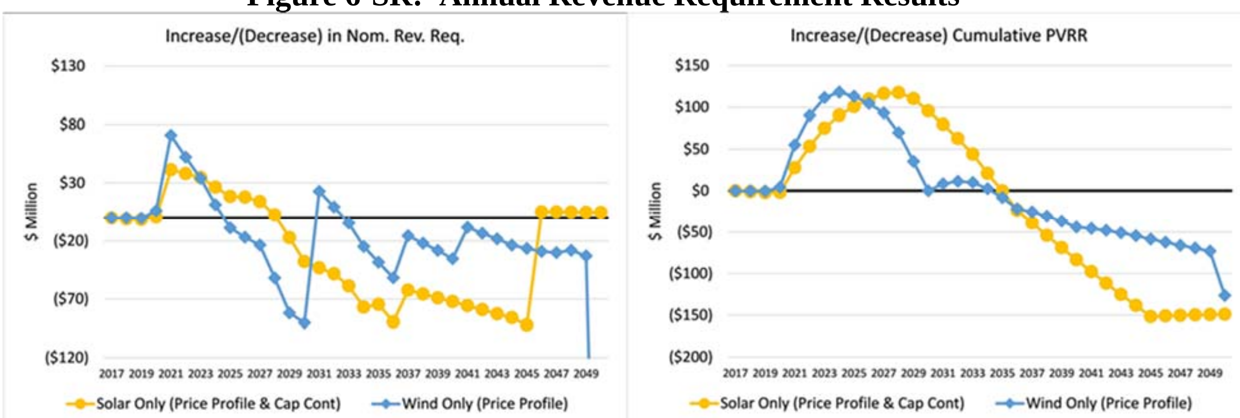
Q. What conclusions can you draw from these sensitivities?

A. The sensitivities set forth above demonstrate that there is risk that the customer benefits from the solar PPAs are overstated because the assumed capacity-contribution value and associated resource-deferral benefits are likely to be lower than what is assumed in the base analysis. Importantly, this same risk does not apply to the Combined Projects. In fact, the Combined Projects will bring additional transmission capacity and a diverse resource that is uncorrelated to solar production (*i.e.*, wind production occurs in all hours, not just daylight hours). Moreover, solar-resource opportunities do not displace the benefits of the Combined Projects, and similarly, the Combined Projects do not displace the potential benefits of solar-resource opportunities. Solar resources are best viewed as an incremental opportunity to the Combined Projects, not as an alternative.

Q. Did PacifiCorp perform an annual revenue requirement analysis to assess how these risks affect the Combined Projects and the 1,320 MW solar-PPA bid portfolio?

A. Yes. Figure 6-SR provides these annual revenue requirement results when applying medium natural gas, medium CO_2 price-policy assumptions. The figure also shows the cumulative PVRR, where the PVRR for each year represents the present value of annual revenue requirement from that year and all prior years.

Figure 6-SR: Annual Revenue Requirement Results



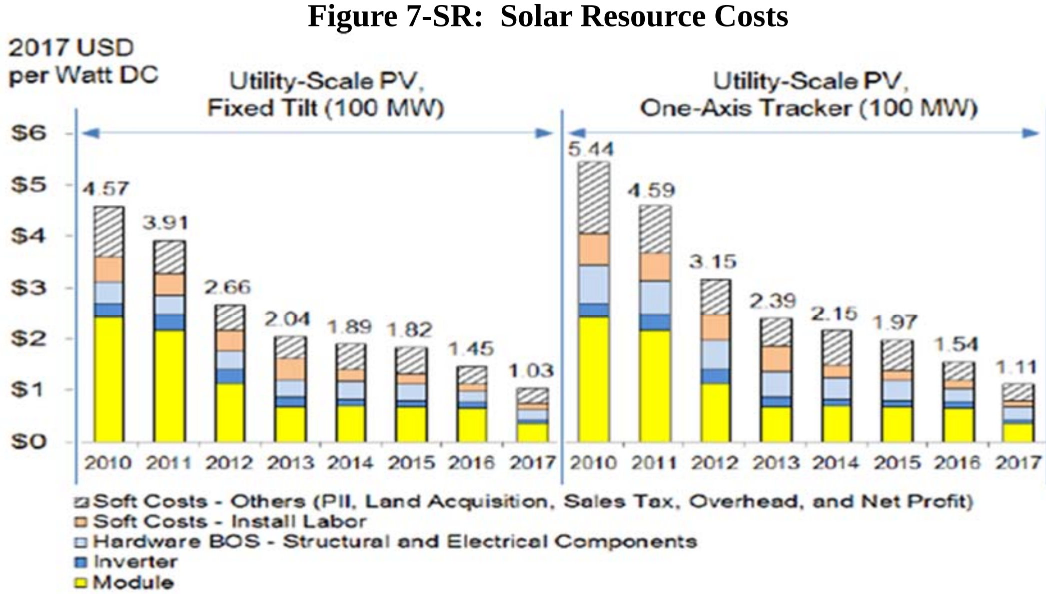
As Figure 6-SR illustrates, the PVRR(d) benefits of the Combined Projects, reflecting an hourly price profile derived from the CAISO day-ahead data, when calculated from nominal revenue requirement results is $127 million. The PVRR(d) benefits of the solar PPAs, reflecting an hourly price profile derived from the CAISO day-ahead data and reflecting a 29.9 percent capacity-contribution value, is $149 million. The Combined Projects have a higher net cost relative to the solar PPAs for two years; however, with PTCs, the net costs drop below the solar-PPA bids beginning year three and the Combined Projects begin producing net benefits by 2025.

The solar PPAs do not begin producing net benefits until 2029. Beyond the first few years, the cumulative PVRR of the Combined Projects is favorable relative to the solar-PPA bids through 2035. Over the long term, more speculative benefits that reflect no further deterioration to hourly price profiles or capacity-contribution value drive the cumulative PVRR benefits of the solar-PPA bids below wind. In 2050, the terminal value assumed for owned assets (applicable to 1,011 MW of the new wind) improves the cumulative PVRR for the Combined Projects.

Q. In addition to the risk associated with hourly prices and capacity contribution, are there any other risks associated with obtaining solar PPAs now as a result of the 2017S RFP?

A. Yes. As shown in Figure 7-SR, solar resource costs have been steadily declining and the trend is expected to continue.

Figure 7-SR: Solar Resource Costs



Source: Fu, Ran, David Feldman, Robert Margolis Mike Woodhouse, and Kristen Ardani. "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017." *National Renewable Energy Laboratory*. September 2017.

As illustrated above, solar resource costs have fallen over time with a

77-percent reduction in utility-scale solar photovoltaic system costs for fixed-tilt systems over the 2010-2017 time frame and an 80-percent reduction for single-axis tracker systems. Stemming from increases in module costs due to a global shortage of Tier 1 module supply, tax-reform uncertainty, and tariff uncertainty, solar costs increased for the first time in the third quarter of 2017 since the Solar Energy Industry Association and GTM Research began publishing market cost reports in 2010; however, cost reductions are expected to continue over the long term. By the second half of 2019, tariff and tax risks, including implications on tax-equity markets, are expected to have been mitigated and module costs are expected to fall to as low as 30 cents-per-watt on a direct-current basis by 2019.[2] Additional reductions to the cost of inverters, tracking structures, and other balance-of-system components are expected to further reduce total-system costs in 2019 and 2020.

Q. How do these changes in solar resource costs impact the company's assessment of the 2017S RFP resources?

A. When considering the relatively long lead time between contract execution of 2017S RFP solar resource bids with commercial operation dates in late 2020, and the fact that the 30-percent ITC is available for solar projects coming online as late as 2021, current pricing for solar resources likely reflects a risk premium, by both bidders and their tax-equity investors, related to tariff and tax-reform uncertainties. Solar pricing received in late 2019 for projects that could come online in 2021 and qualify for the 30-percent ITC should reflect expected cost reductions and avoid the current risk

[2] "Why Solar Is on a Path to Dominance," *Greentech Media*, Yuri Horwitz, February 15, 2018 (available at https://www.greentechmedia.com/articles/read/solar-is-going-to-win-bigly).

premium associated with tariff and tax-reform uncertainties.

Q. Mr. Hayet claims that the company did not discuss the nominal revenue requirement results through 2050 for the solar sensitivity presented in the second supplemental direct testimony. (Hayet Second Rebuttal, lines 557–585.) How do you respond?

A. As I described in my supplemental and second supplemental direct testimonies, the company's system-modeling analysis demonstrated that the combined benefits of the solar resources and the Combined Projects were higher than the individual benefits of each resource option alone. Mr. Hayet does not dispute that conclusion.

As I discussed earlier, the system-modeling results provide a view of the economic analysis that is consistent with the planning period and approach used to identify a least-cost, least-risk preferred portfolio in the IRP. While the nominal revenue-requirement analysis provides a sense of how the Combined Projects and solar resources might impact customer rates over time, longer-term results in this analysis are increasingly difficult to project. The company focused on the system-modeling results when performing its solar resource sensitivities because these studies are more suitable for comparing different resource portfolios, consistent with how resource portfolios are evaluated in the IRP.

Q. Mr. Mullins and Mr. Hayet claim that the nominal revenue-requirement results show that solar PPAs are a superior resource option when compared to the Combined Projects. (Hayet Second Rebuttal, lines 557–585; Mullins Supplemental Rebuttal, lines 402–411.) How do you respond?

A. First, Mr. Hayet and Mr. Mullins do not dispute that the customer benefits of the

Combined Projects and the solar resources together are higher than each resource option alone when analyzed over a 20-year time frame, consistent with evaluation of resource portfolios in the IRP. That is the key finding reported in my solar sensitivity analysis.

Second, as described above, there is a risk that benefits of the solar PPAs reported in my second supplemental direct testimony are overstated, as demonstrated by the additional sensitivities discussed above, and that these risks could increase over time.

Q. If the Bridger/Anticline transmission line is included in the base case as discussed above, does that demonstrate that the Combined Projects are more favorable than solar PPAs in the nominal revenue-requirement results?

A. Yes. Including the net present-value costs of the transmission line in the base case adds $293 million in net benefits to the Combined Projects, for a total of $467 million in net benefits in the medium case.

Q. These witnesses also claim that the solar option is also less risky than the Combined Projects because the solar resources are PPAs. (Mullins Supplemental Rebuttal, lines 421-422; Hayet Second Rebuttal, lines 581-585.) Is this true?

A. No. These parties' focus on only the commercial structure is overly simplistic. As described above, solar resources generally present additional risks that do not apply to wind resources. Specifically, solar resources tend to generate most during the day, when demand and prices are relatively low. Because the generation profile of solar resources is consistent across the west, the increasing penetration of solar resources throughout the region will likely further depress prices during the period when solar generates.

Thus, there is a risk with solar that the value of the generation provided will be less than current forecasts and could be less than projected in the hourly price-profile sensitivities.

Moreover, the capacity contribution of solar resources is likely decreasing as solar penetration increases. As discussed above, this is a risk that is unique to solar resources and means that the customer benefits for solar resources are likely overstated.

Q. Are there any other risks associated with pursuing solar resources now?

A. Yes. Dr. Zenger and Mr. Hayet claim that the solar PPAs are less risky because they do not require the Aeolus-to-Bridger/Anticline transmission line. (Zenger Supplemental Rebuttal and Surrebuttal, lines 207–210; Hayet Second Rebuttal, lines 581–583.) But, as described by Mr. Vail, that transmission line is needed today and will provide substantial customer benefits independent of the fact that it will enable interconnection of the Wind Projects. And, as described by Mr. Vail, the company currently anticipates construction of the line by 2024 even without the Combined Projects. Thus, far from reducing customer risk, if the company selected the solar PPAs instead of the Combined Projects, it would create a very real risk that customers would ultimately bear the cost of the Aeolus-to-Bridger/Anticline line without the cost offset provided by the PTC-eligible Wind Projects. And as I discussed earlier, the company's economic analysis of the Combined Projects is conservative because it does not consider the cost of the Aeolus-to-Bridger/Anticline transmission line in the base case. As shown above, accounting for this cost in the base case would improve the net benefits from the Combined Projects by hundreds of millions of dollars in all price-policy scenarios.

Q. Dr. Zenger claims that "Utah solar resources should have been considered in this docket along with the Combined Projects." (Zenger Supplemental Rebuttal and Surrebuttal, lines 213–215.) Is this position consistent with DPU's prior position on the 2017R RFP?

A. No. In the docket where the Commission approved the 2017R RFP, DPU testified that the "RFP should be restricted to wind-only resources" because the "point of issuing the RFP is to potentially reap the benefits of the PTCs." *In the Matter of the Application of Rocky Mountain Power for Approval of Solicitation Process of Wind Resources*, Docket No. 17-0035-23, DPU Exhibit 1.0 REB, lines 151–152 (Sept. 13, 2017).

CONCLUSION

Q. Please summarize the conclusions of your surrebuttal testimony.

A. As confirmed by two different independent evaluators, the 2017R RFP was fair, transparent, and unbiased. The independent evaluators found that the bids selected to the 2017R RFP final shortlist represent the top offers that are viable under current transmission planning assumptions, and the Utah independent evaluator found that the final shortlist of bids should result in significant savings for customers. While solar-resource bids submitted into the 2017R RFP may provide customer benefits, contrary to claims from certain parties, solar-resource bids are not a superior resource alternative to the Combined Projects. When considering solar resource valuation risks, expected cost declines, and availability of the 30-percent ITC for solar projects coming online as late as 2021, PacifiCorp does not need to act now and has decided not to select any of the solar-PPA bids to the 2017S RFP final shortlist. PacifiCorp will continue to reassess potential economic benefits from solar-resource opportunities through bi-lateral opportunities and in the 2019 IRP, considering a thorough assessment of valuation risks with full stakeholder engagement, to determine whether a new competitive solicitation process for projects capable of achieving commercial operation by the end of 2021 will provide customer benefits.

In contrast, the phase out of PTC benefits that are available for qualifying wind projects occurs sooner than the ramp down of ITC benefits that are available for solar resources, which requires that PacifiCorp must act now to deliver the new wind and needed transmission investments that will partially offset projected capacity needs and produce both near-term and long-term benefits for customers. This conclusion is supported by thorough and extensive economic analyses that is based on over 1,300 20-year simulations of PacifiCorp's system, which have been used to evaluate how the net benefits of the Combined Projects are affected by a variety of variables and uncertainties.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-1SR)
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 Surrebuttal Testimony of Rick T. Link

Oregon IE Report

May 2018

PUBLIC VERSION

THE INDEPENDENT EVALUATOR'S FINAL REPORT ON PACIFICORP'S 2017R REQUEST FOR PROPOSALS

Presented to:
OREGON PUBLIC UTILITY COMMISSION

Prepared by
Frank Mossburg
Vincent Musco
Karen Morgan

February 16, 2018

1300 Eye Street NW, Suite 600
Washington, DC 20005
202-408-6110

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I. INTRODUCTION AND SUMMARY

A. INTRODUCTION

This is Bates White's Final Closing Report on PacifiCorp's 2017R Renewables RFP ("2017R RFP" or the "RFP"). Bates White served as the Independent Evaluator ("IE") for this RFP. The primary purpose of this report is to provide the Oregon Public Utility Commission ("Commission") with the IE's recommendation with respect to the acknowledgement of PacifiCorp's ("the Company's") selection of a Final Shortlist. This report is also intended to provide the Commission with a record of the development and evaluation process for both the Initial and Final Shortlists.

B. RECOMMENDATION REGARDING THE FINAL SHORTLIST

Bates White recommends that the Commission acknowledge the Final Shortlist as presented. Based on the results of portfolio optimization modeling, stochastic risk analysis, and review of viability factors, the Company has selected four projects for the Final Shortlist representing approximately 1,300 MW. These projects are

- TB Flats I & II – A proposed 500 MW wind project located in Carbon and Albany Counties, Wyoming. This project is to be developed by PacifiCorp's Benchmark team based on a site developed by Invenergy.

- Cedar Springs – A 400 MW wind project located in Converse County, Wyoming. This project is to be developed by NextEra Energy Acquisitions. Half of the project will be sold to PacifiCorp under a Build-Transfer Agreement ("BTA") while the other half will sell power to PacifiCorp under a Power Purchase Agreement ("PPA").

- Ekola Flats – a proposed 250 MW project located in Carbon County, Wyoming. This project is to be developed by PacifiCorp's Benchmark team based on a site developed by Invenergy.

- Uinta – A proposed 161 MW wind project located in Uinta County, Wyoming from Invenergy Wind Development. The project will be sold to PacifiCorp under a BTA Agreement. Unlike the top three projects this project does not require the completion of the Aeolus-to-Bridger/Anticline Segment ("D2 Segment") in order to be deliverable to PacifiCorp's system.

Our recommendation is based on the following points.

- The selected bids represent the top offers that are viable under current transmission planning assumptions and provide the greatest benefit to ratepayers as determined by the Company's System Optimizer ("SO") and Planning and Risk ("PaR") models.

- The selected bids represent the best viable options from a competitive process. The RFP received bids from 13 suppliers offering a total of 18 projects representing about 4,900 MW. Some of these projects offered multiple options. In total there were 59 bid options presented. Offers were received from projects both inside and outside the Company's constrained area in Wyoming and included variations in design such as different turbines and contract structures.

- Our independent analysis confirmed that the selected bids were reasonably priced and, while not the lowest-cost offers, were the lowest-cost offers that were viable under current transmission planning assumptions. Our analysis included the creation of our own cost models for each bid option, a review of PacifiCorp's models and a review of the terms and conditions of each bid.

- Two company-sponsored Benchmark bids were chosen and we took special care to confirm those selections. We confirmed the accuracy of the Benchmark costs and scoring and provided the Commission with a complete review of all costs of each project prior to bid receipt. We also confirmed the Benchmark's status by: (a) reviewing the project's Initial and Final Shortlist scores and models, (b) independently scoring the project's non-price characteristics, (c) comparing the cost and output of the project to recent third-party bids, and (d) evaluating the bid costs in our own cost model. The bids were also disciplined by the fact that a third-party bidder submitted a competing offer for a BTA for each project.

- To the best of our knowledge the RFP aligns with the Company's Integrated Resource Planning ("IRP") process, as well as its 2017 IRP Plan, which was filed on April 4, 2017 ("2017 IRP"). The Initial and Final Shortlist analyses used current assumptions from the IRP. The models used to select the Final Shortlist were the same models that the Company uses in its IRP process. While it is our understanding that the action plan from the 2017 IRP (which includes this resource acquisition strategy) is approved, we have yet to see a final approval order and are unaware of any potential conditions that may come with such an order. For the purposes of this report, we assume that the 2017 IRP will be approved without any conditions that may alter our recommendation here.

Additionally, we base our recommendation on our participation in the entire RFP process from design, through bid receipt and analysis, to selection of the Initial and Final Shortlists. During that time we:

1. Reviewed and commented on drafts of the RFP;
2. Attended the pre-bid conference;
3. Monitored bidder contact, including the answers to bidder questions;
4. Confirmed the assumptions used in the analyses;
5. Confirmed the initial qualification of bidders and the confirmation of proposal details;
6. Provided input with respect to bidder disqualifications;
7. Reviewed the price and non-price scores and models for the Company's Initial Shortlist process and confirmed the Company's selection of an Initial Shortlist; and

8. Reviewed the models for the selection of the Initial and Final Shortlist and confirmed the Company's selection of the Initial and Final Shortlist.

Throughout the process we were in constant contact with PacifiCorp's evaluation team. The Company was transparent in their discussions with us and provided all information that we asked within a reasonable timeframe.

We note that we will also be monitoring the negotiations of final contracts with the winning bidders to ensure that actual signed contracts match the offers submitted and evaluated. In the case of the Benchmark resources we will monitor the negotiation of EPC contracts for the facilities.

C. ADDITIONAL RECOMMENDATIONS TO PROTECT RATEPAYERS

We have additional recommendations related to the RFP to help protect ratepayers from bearing undue risk. First, in order to protect ratepayers and ensure that they receive the benefits promised during this RFP we would recommend that all selected resources to be owned by the Company (i.e., BTAs and Benchmark resources) be held to their capital and operations and maintenance ("O&M") cost projections as provided with the bid. These amounts should be considered a "hard" cap, meaning that there will be no opportunity for the Company to collect additional costs even if they believe such expenditures were prudent. Doing so will help give the offers a risk profile much closer to that of a PPA, requiring the Company to take risks that typical wind developers take, and insulate ratepayers from the risk of cost overruns. Because the majority of construction costs will be covered under the BTA agreement or, in the case of Benchmarks, a negotiated engineering, procurement, and construction ("EPC") agreement, we feel this is a reasonable requirement.

Second, ratepayers should not be harmed if either PacifiCorp or the project developers fail to acquire 100% of the value of the Production Tax Credit ("PTC"). PacifiCorp should provide an unconditional guarantee (i.e., not subject to force majeure or change in law) that ratepayers will receive the full projected value of the Production Tax Credit. This includes situations where (a) PacifiCorp cannot claim full PTC value or (b) PacifiCorp does not have the taxable income to use the full PTC value. Again, this is similar to what is expected of a third-party developer.

Third, the Company should similarly be held to their cost projections for the Aeolus-to-Bridger D2 Segment. PacifiCorp's resource acquisition strategy here – which includes three projects that rely on the D2 Segment's construction for economic viability – is based on a certain cost promise for this segment and the Company should be held to its promises.

D. ADDITIONAL COMMENTS AND RECOMMENDATIONS

Based on our work in this RFP we have several observations and recommendations to assist parties moving forward. First, parties should make more effort in the future to align the RFP process with the IRP process. This process was rushed in order to meet deadlines for qualification for full value of the PTC. However, the PTC's sunset has been known since the end of 2015. We were not involved in the IRP process but are unaware of any reason why this fact could not have been incorporated into planning at an earlier time. Moreover, as of today there is still no written order approving the Company's IRP, which cast additional uncertainty over this RFP process.

Second, and related to the above point, transmission planning should better align with IRP planning. One troubling aspect of this RFP was that the initial system impact studies provided to bidders did not incorporate the early completion of the D2 Segment. After revisions to account for the earlier in-service date of the D2 Segment were incorporated it was determined that only projects with early queue positions could be deliverable to load without the completion of the entire Gateway South project in 2024. These evaluations by PacifiCorp's transmission group essentially left us with only about four potential offers in the transmission-constrained area served by the D2 Segment. We realize that there are functional separations within the Company but having alignment between the planning side and the transmission side will help make more informed decisions in the future.

Third, future RFPs using the Company's production cost modeling should examine (as a sensitivity) resource choice with levelized benefits as well as costs. While the issue ultimately had no impact on winning projects selected in this RFP due to the transmission issues noted above, the Company's modeling method, which levelized cost but not the benefits of PTC acquisition, could have biased the bid selection to less favorable offers.

Fourth, regarding the winning Cedar Springs project, which is 50% BTA and 50% PPA of 200 MW each (for a total of 400 MW), we note that the [redacted]. Additional analysis shows this option to be preferable to the selected option across several years, but slightly less preferable over the entire 30-year expected life of the facility. We believe the Company's selection of the 50-50 BTA/PPA option is reasonable, but note that the PPA option would also be a reasonable choice given its superior risk protections and additional portfolio flexibility.

Fifth, because the selected portfolio contains mostly options to be owned by the company, the selected portfolio generates significant PTC benefits within the first ten years of operation. These benefits credit against revenue requirements and serve to lower costs in this initial period. However, after the end of the ten-year PTC window these credits disappear and costs increase. PacifiCorp currently projects a $125 million cost increase in 2031. If the Commission believes such an increase would be unreasonable they should consider enacting some form of rate mitigation efforts in the future.

II. RFP ISSUANCE TO BID RECEIPT

PacifiCorp's RFP was approved by the Commission, with modifications, in a special public meeting on August 29, 2017. The Commission ordered modifications to the RFP regarding IRP acknowledgement, eligibility of existing resources, minimum bid requirements, credit requirements and terms in the *pro forma* PPA. PacifiCorp made the required changes to the RFP and provided a revised RFP to the IE prior to issuance of the final RFP to the market. We reviewed the changes made, had no objections, and the final RFP was approved by the Commission on September 26, 2017.

The final RFP was issued on September 27, 2017 and was subject to an accelerated schedule. The accelerated schedule was designed to allow winning bidders to capture the full value of the PTC by placing their projects into service prior to December 31, 2020,[1] and to align with the Company's Certificate of Public Convenience and Necessity ("CPCN") process to expand its transmission system in Wyoming in order to accommodate projects selected in this RFP.

Since PacifiCorp issued the RFP in late September the following steps have been completed:

Table 1: Milestone Events to Date

Milestone	Date
RFP Issued to Market	9/27/2017
1st Bidder's Conference	10/02/2017
Notice of Intent (NOI) to Bid Due	10/09/2017
Last Day for RFP Questions to IEs for Q&A	10/10/2017
Benchmark Bids Due	10/10/2017
RFP Bids Due – Wyoming Wind	10/17/2017
RFP Bids Due – Non-Wyoming Wind only	10/24/2017
Bid Eligibility Screening Completed	10/30/2017
Initial Shortlist (ISL) Evaluation/Scoring Completed	11/7/2017
Capacity Factor Evaluation on ISL started	11/12/2017
IEs' Review of ISL Completed	11/17/2017
ISL Price Update	11/22/2017
Capacity Factor Evaluation on ISL Completed	11/27/2017
Price update for Tax Reform Bill	12/21/2017
Final Shortlist Evaluation Completed	2/12/2018
IE Report submitted to OPUC	2/16/2018

Bates White has actively participated at each step of the RFP process. We have been in constant contact with the Company, Commission Staff and have had multiple discussions on many issues. In addition, throughout the process we have coordinated with Utah's independent evaluator to ensure that the rules of the RFP were applied consistently across both states.

PacifiCorp held a Bidder's Conference on October 2, 2017. The conference was simulcast in Portland, Salt Lake City, and online. Bates White attended the conference in

[1] RFP, page 1.

Portland. PacifiCorp personnel walked through the RFP process, including bid qualification and evaluation. Several questions were raised regarding a range of issues including bid fees, contract requirements, schedule, and submission requirements. PacifiCorp answered most of these questions at the conference and the reminder of the questions later via a posting on the RFP website. Bidders asked questions up until the final day for questions of October 9, 2017. Bates White reviewed all questions and answers prior to posting.

After the bid conference, PacifiCorp presented us with the assumptions to be used in bid evaluation. These included items such as cost of capital, asset lives, and forward market values. We reviewed the assumptions file and asked PacifiCorp questions in order to determine that the numbers used were consistent with the most recent IRP process or (for certain items) reflected the most recent Company forecasts.

Bidders were to submit NOIs by October 9, 2017. Submissions were made electronically and Bates White was copied on all submissions. In total, 19 companies indicated their intentions to bid by submitting NOIs. We received no indications that there were companies who wanted to submit an NOI but failed to do so. A list of those companies providing NOIs is presented in Table 2.

Table 2: Summary of NOI Submissions

Ownership of Bidders (Bidder name if different)[2]	State
[redacted]	Idaho
	Wyoming
	Wyoming
	Montana
	Idaho
	Wyoming
	Wyoming
	Utah
	Montana
	Wyoming
	Wyoming
	Wyoming
	Wyoming
	Wyoming
	Washington
	Wyoming
	Oregon
	Wyoming
	Wyoming

In the NOI bidders were asked to identify the types of proposals they might submit as well as the project size. Table 3 summarizes the indicated bids by state, type, (BTA or PPA) and size (in MW). The potential response was heavily weighted toward Wyoming wind offers and far in excess of the RFP's targeted solicitation of 1,270 MW.

Table 3: Summary of Indicated Bids

	PPA		BTA	
	Number of Proposals	MWs	Number of Proposals	MWs
ID	2	200	1	110
MT	3	400	-	-
OR	1	187	1	187
UT	2	180	1	100
WA	1	145	1	145
WY	21	6,194	12	3,365
Total	**30**	**7,305**	**16**	**3,906**

[2] Listing for ownership is name of entity providing credit support.

III. BENCHMARK BID ANALYSIS

On October 10, in accordance with the RFP timeline, PacifiCorp's Benchmark team submitted their offers to the IE and the PacifiCorp evaluation team. In total, there were four benchmark offers submitted. These projects are shown in Table 4.

Table 4: Benchmark Project Summary Data

Project Name	Nominal Capacity (MW)	Turbine Manufacturers	Number of Generators	Wyoming County	COD
Ekola Flats	250	[redacted]		Carbon	11/1/2020
McFadden Ridge II	110			Albany/Carbon	11/1/2020
TB Flats I	250			Carbon	11/1/2020
TB Flats I & II	500			Albany/Carbon	11/1/2020

Source: Project Applications, Appendix C

Bates White next undertook a review of the offers. In assessing a utility's own bids in response to the RFP, our greatest concern is that the utility will incorporate cost estimates that have been aggressively estimated and do not characterize the costs of the project accurately. To determine whether this had occurred, we looked at a detailed breakdown of each of the benchmarks costs to determine if any items have been improperly omitted from the cost calculation, and at overall capital cost levels by comparing them to publicly-available data on recent wind generation capital costs. Such a comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors.

We found that the Benchmarks were acceptable based on three items. First, the benchmarks were not deliberately underpriced through omission of any capital cost components. Second, the benchmark capital and operating costs appeared reasonable when compared with public data on U.S. wind projects. Third, the capacity factors of the benchmarks were reasonable when compared with public data and were supported by credible third-party analysis. Bates White's detailed assessment of the Benchmark bids is included as Appendix A to this report.

In addition, as required by the Oregon Competitive Bidding Guidelines, we reviewed PacifiCorp's price and non-price scoring of the benchmarks prior to receipt of third-party offers. The price score was based on a comparison of the bid's costs to the market value of the energy the bid would replace. The non-price score was based on criteria laid out in the RFP. Bates White confirmed the price scores by inputting key bid criteria into our own busbar levelized cost model. Additional details about all scores, as well as the actual scores, are provided later in this memo. All scoring was confirmed prior to the review of third-party offers, per Oregon's Competitive Bidding Guidelines.

IV. BID RECEIPT AND QUALIFICATION

Bids from third-party bidders were due on two separate dates. Wyoming project proposals were due on October 17. Non-Wyoming proposals were due a week later. Bates White suggested this bifurcation, noting that the original draft RFP did not allow bids from outside Wyoming. Only after a last-minute modification to the RFP were non-Wyoming bids allowed to participate. Our suggestion to allow non-Wyoming bidders an extra week to prepare their bids was meant to recognize the reduced notice afforded to them.

Bates White supervised in person in Portland the receipt and opening of the bids on both third-party bid receipt dates. No bids were rejected for being untimely and there was no indication that any bidder had offers they wished to submit but were unable to do so.

Ultimately, ignoring those who did not bid or whose bids were deemed to be non-compliant (discussed below), 13 suppliers submitted a total of 18 projects representing almost 4,900 MW—which is about 3.9 times the quantity solicited. The majority of these projects were Wyoming wind projects. Specifically, 14 projects representing around 4,400 MW were based in Wyoming while four projects representing 485 MW were located outside of Wyoming. Some projects contained several options, typically differences in project size, equipment, or transaction type (i.e., PPA versus BTA or a combination thereof). In total, bidders submitted 50 Wyoming bid options and nine non-Wyoming bid options.

One notable set of submissions came from Invenergy. These submissions were notable because they were third-party BTA offers for three of the four Benchmark sites (all sites except McFadden Ridge). Invenergy currently holds the development rights on these three sites and under their agreement with PacifiCorp's development team, both parties were free to offer bids into the RFP. We viewed this as a positive sign because it provides a transparent and above-board market offer to compare with the Benchmarks.

Fees for proposals were structured such that the bidder paid a fee of $10,000 covering a base proposal and two alternatives. Each bidder was permitted to offer up to three additional alternatives to the base proposal (maximum of six) at a fee of $3,000 per alternative. After the receipt of offers, PacifiCorp worked with bidders to confirm and collect bid fees. PacifiCorp and the bidders were able to come to agreement on fee amounts.

Upon final receipt of bids and bid fee confirmation, PacifiCorp went to work confirming bid details with bidders. Bidders provided and confirmed project information and provided update information where their original response was lacking. Bates White participated in calls with the bidders to make sure that all parties understood the terms and conditions of the bid and any deficiencies encountered.

Once the bids were confirmed, PacifiCorp and the IEs reviewed the offers for qualification purposes. Bids were held to several minimum requirements. Key requirements included: (a) being wind powered offers, (b) demonstrating that the project could be commercially operational by December 31, 2020, (c) being located in or demonstrating deliverability to PacifiCorp's system, (d) having requested interconnection with PacifiCorp's system or a third-party system and (at a minimum) having a feasibility study in progress, (e) compliance with and verification of major equipment availability (wind turbines), and (f) having one to two years of wind data from the site.

We discussed potential disqualifications with PacifiCorp and the Utah IE. Ultimately, four bidders had projects disqualified from consideration for the Initial Shortlist. The disqualified Wyoming projects were as follows:

1. [redacted] Farm was rejected for containing an unacceptable level of development risk. The project was still in the conceptual stage, the bidder did not have site control, and relied on "virtual" met tower data.
2. [redacted] withdrew its [redacted] proposal from consideration for the short-list because the project was proposing an unacceptable transmission structure. The project was located outside of PacifiCorp's system and proposed using a "pseudo-tie" for delivery rather than securing firm delivery to the system.

The rejected non-Wyoming projects were as follows:

1. Caithness Energy's Beaver Creek projects were disqualified as non-compliant as they did not offer a wind-only option as required by the RFP. Their offer was for a wind farm mixed with battery storage. In addition, their proposal presented issues with transmission service as their proposal required a third party to take title to the energy prior to receipt by PacifiCorp.
2. [redacted] project was rejected due to the fact that it was not a wind-only resource as required by the RFP. [redacted] had proposed a PPA from a pumped storage facility which might possibly be combined with wind and solar projects at a later date.

Bates White was consulted on the decision to remove each of these bidders and bid options and we agreed with the decision to remove them. Caithness pronounced themselves "very disappointed" that PacifiCorp did not accept their option, which they believed had real value for bidders. During discussions with the bidder PacifiCorp made clear that the failure to offer a wind-only option was the primary reason for the disqualification. [redacted] offer was also rejected due to the fact they did not offer a wind-only resource (though their project consisted of other resource types beyond storage).

In making the disqualification PacifiCorp had to point to a reference in the RFP that supported this decision. While the RFP, plainly read, asks only for "new wind resources", the closest specific language in the RFP document is Section 3.H.13 which states: "proposal presents an unacceptable level of development or technology risk." Caithness offered the argument, which has some validity, that their project did not, in fact, pose any technology risk. However, the fact remains that the offer was not a wind-only project and would not match the plan resulting from PacifiCorp's approved IRP. If the RFP was interested in dispatchable wind then it would have stated so clearly in the document.

It is true that PacifiCorp and the IEs could have decided to allow the offer. However, the issue with this decision is that other developers may have claimed – based on a clear reading of the RFP – that such an offer was not permitted and, had they known, they would have offered into the RFP in a different manner than they ultimately did. Yet another issue with granting the request is that the bid evaluation method would have to be re-examined in order to ensure it was capturing the full value of a dispatchable wind offer. In our experience these offers typically are not cost-competitive and only stand to succeed if the evaluation places a high value on the storage component.

Another factor is whether or not a storage-aided facility would truly count as a "renewable" resource. In California's Green Tariff Shared Renewable programs, which aim to bring renewables to those who want a larger share than under California RPS standards or who want to participate in community-based solar programs, storage is not allowed because it typically charges from the grid.

We note here that a cursory glance at Caithness offer prices, which ranged from around [redacted], would likely not have proven to be valuable when compared with the prices offered by other resources. PacifiCorp did tell the Caithness team that they were welcome to discuss the project in the context of a bilateral transaction and we share that sentiment. If the Commission is interested in pursuing more storage we would recommend that a separate procurement be held for such resources.

V. INITIAL SHORTLIST DEVELOPMENT

After the bids were received and bid details were confirmed, the Company began the Initial Shortlist evaluation. Per the RFP, each bid was scored on price and non-price factors. The total bid score was weighted at a maximum 80% for price and a maximum 20% for non-price factors. The non-price factors were defined as follows:

Table 5: Non-Price Factor Weighting

Non-Price Factor	Non-Price Factor Weighting
Conformity to RFP Requirements	4%
Project Deliverability	8%
Transmission Progression	8%

Price score was based on a comparison of the cost of the bid to the benefits of the bid. Costs differed based on the type of bid. For BTA bids the costs were:

(a) the revenue requirement needed to cover the project's capital cost (less the full Production Tax Credit),

(b) O&M costs, including maintenance capital and royalty payments,

(c) property tax,

(d) wind integration cost,

(e) network upgrade costs, and

(f) Wyoming generation taxes.

For PPA bids the costs included:

(a) the PPA price,

(b) network upgrades, and

(c) integration costs.

The major benefit for both types of offers was captured by the value of the energy replaced by the project. This value was based on one of three forecasts of benefits based on project location (Wyoming, Utah/Idaho, or Oregon/Washington). Each forecast was created by PacifiCorp's IRP team by running production costs models with and without proxy wind resources and measuring the increase in cost at each location. Energy benefits for each project were calculated based on the specific generation output of a given project. Beyond energy value, BTA bids were assigned a terminal value to account for the fact that PacifiCorp would own the site at the end of the project's useful life.

Bids were ranked in separate categories, "Wyoming Wind" and "Non-Wyoming Wind." In this context, "Wyoming Wind" meant projects whose deliverability was enabled by the D2 Segment. This was done because PacifiCorp's evaluation did not take into consideration the cost of the Aeolus to Bridger transmission expansion (a cost that was included in the Final Shortlist evaluation). We were concerned that ignoring this cost would place non-Wyoming offers at a disadvantage.[3]

A. RANKING THE BIDS

Bates White independently verified the rankings in three ways. First, we reviewed each model on a line-by-line basis to make sure that the details of the bids were properly input and that all bids used the same default assumptions. Second, we reviewed the terms and conditions of the bids and compiled our own non-price scores. Third, we tested PacifiCorp's models by inputting key costs of each bid option into our own cost model, which determined an annual $/MWh annuity cost for the bid option. After we reviewed the bids we conferred with both PacifiCorp and the Utah IE to come to a consensus on shortlist candidates.

Wyoming Wind

The ranking of all the Wyoming Wind bid options is shown in Attachment One. Our simplified cost models were able to match PacifiCorp's models reasonably well. On average PacifiCorp's models showed a higher cost by $0.27/MWh and in 46 out of the 50 cases the difference was less than a dollar per MWh.

The table below shows the offers for each project with the greatest net benefit, in other words, options proposed for the same project with lower net benefit are removed for clarity.

[3] Specifically, the Aeolus-to-Bridger transmission project – which has yet to be approved and built – will benefit all Wyoming-based bids, including the Benchmark bids. It is important for the RFP evaluation process to consider the cost of the transmission project in comparing bids, particularly in comparing Wyoming-based bids – which are most likely to benefit from the transmission project – to non-Wyoming bids, which are less likely to benefit from the transmission project.

Table 6: Best Offers from Each Wyoming Wind Project

[redacted]

Table 6 allows us to make a few observations. First, the offers were very close in value. Thirteen of the projects offered net benefits of between $25/MWh and $30/MWh. This bunching means that small assumptions can have a large impact on ranking. Second, we see that PacifiCorp's terminal value adders were fairly small, about $1.18/MWh on average. Third, term length does have an effect on the net benefits. The average energy benefit for projects with terms less than 30 years is $46.76/MWh while the average benefit for 30-year projects is $48.74/MWh. This difference is mostly driven by the fact that the value of energy replaced increases in later years. These latter two items give a small advantage to BTA bids (since all BTA offers are assumed to last for 30 years). Again, the difference is not vast, but it can have an impact when bids are bunched so close together. This is why the [redacted] BTA offers from [redacted] and [redacted] were ranked just ahead of the lower-cost [redacted] PPA offer from [redacted]. Finally, the Invenergy offers for the Benchmark sites were generally [redacted].

To translate these net benefits into a price score and create a final ranking, PacifiCorp utilized three scoring methods. First, the offers were "ranked' with the most beneficial bid receiving a score of 80 points, a breakeven bid (i.e., a bid with zero net benefit) receiving zero points, and any scores in between being interpolated. Second, the offers were "force-ranked," with the most beneficial bid receiving 80 points and the least beneficial receiving zero points, with in-between scores being interpolated. Finally, PacifiCorp used the "force ranking" concept, but used a "rank order" method to score all offers between the highest- and lowest-ranked offers. So, if there were nine bids, the best would receive 80 points, the second-best bid would get 70 points, the third-best bid would get 60 points, and so on, with the worst bid receiving 0 points).

In each method PacifiCorp combined their scores with the non-price score to get a final bid ranking. The results are shown in Table 7.

Table 7: PacifiCorp's Scores for Selected Projects

[redacted]

This table shows that regardless of the scoring system (e.g., "Cases" 1, 2, and 3) utilized, the actual project rankings did not change. This is an important point to underscore. Nevertheless, there are a couple other points to draw out from Table 7. First, there was a relatively big gap between the [redacted] project and the [redacted] project, which suggested a logical threshold for determining the shortlist. Second, under the first scoring method price scores were tightly bunched, with eight projects scored between 80 and 89 points. This meant that non-price factors could have a larger impact on bid selection. Having said that, non-price scores were relatively similar, with the exception of the [redacted], which were lower than those for other bidders.

In order to select bid options for the Initial Shortlist, PacifiCorp and the IEs proceeded with the following goals in mind:

1. Selecting the bids with the greatest net benefit in terms of price and non-price benefits,
2. A diversity of bidders and projects,[4]

[4] This can minimize the risk of relying on the success of one given project or a given bidder.

3. A mix of PPAs and BTAs,
4. A relatively clear split between the score of the last bid picked and the next bid that was not selected, and
5. The RFP goal that there be a minimum of 2,000 MW selected.

PacifiCorp's recommended Initial Shortlist relative to other top-performing projects is shown in [redacted].

[redacted]

[redacted]

Source: PacifiCorp, 2017R RFP – Wyoming Initial Short List Update – 2017-11-06 IE V4.pptx

The Initial Shortlist was comprised of nine projects including four PPAs, two BTAs, and one PPA/BTA combination. All three Benchmark projects were selected to the shortlist. (Figure 1 above omits the [redacted] because the [redacted] offer for the same site scored higher, but, as seen on Table 6, the [redacted] offer scored among the top offers, which earned it the right to move on to the next round.) If a project was selected, <u>all alternatives</u> for a given project were selected as well.

The nine projects represented a cumulative installed capacity of approximately 3,100 MW, significantly above the RFP's stated target shortlist size of 2,000 MWs. The reason for such a large selection of projects was the tight bunching of the offers. As noted above, when looking for a selection of projects we typically try to identify "gaps" in value. The first such gap appears between the [redacted] and [redacted] projects. This is shown on both figure one and above in Table 6.[5] While the [redacted] were also low scorers on the non-price side, the gap appears in the price score as well. As can be seen on Table 6 there is about a [redacted] gap between the [redacted] project and the [redacted] offer.

While we did consider imposing a stricter limit on the selection, ultimately, it was considered more advantageous to include more projects in the Final Shortlist evaluation. This is especially true given that all bids would be allowed to submit a best and final offer (BAFO) and the offers were so tightly bunched that any changes resulting from the BAFO could certainly alter the rankings. In addition, we did consider pushing for the exclusion of the McFadden Ridge project on the grounds that it would not be included in the shortlist without the assistance of the terminal value adder and the additional value resulting from its assumed 30 year operational life. We ultimately decided to allow it because (a) the bid was scored properly according to the rules of the RFP and (b) this was simply a selection to the Final Shortlist evaluation, not a selection for a winning bid.

Non-Wyoming Wind

As noted above, the Non-Wyoming Wind category received substantially fewer offers than the Wyoming category. This was not totally surprising since the category was added at the last minute per the decision of the Utah PSC. Only four qualified projects were submitted in this category. The table below shows all options considered in the evaluation

Table 8: Non-Wyoming Offers (All Qualified Options)

[redacted]

[5] Note that the values in Figure 1 differ slightly from the values in Table 6 above and in the Appendix. Figure 1 comes from PacifiCorp's presentation to the IEs and regulators while the numbers in the other sources are taken straight from PacifiCorp's cost models. In any case, the bid order is the same.

Table 8 makes it clear that these bids do not provide the same level of benefit as the Wyoming Wind offers. This is not unexpected given both (a) the quality of the wind resource in Wyoming and (b) PacifiCorp's projected energy market benefits – which are higher in Wyoming than elsewhere. Of course, the Wyoming bids did not include the cost of the proposed transmission upgrade— again, this was considered in the Final Shortlist evaluation.

The [redacted] was the only non-Wyoming project which provided positive net benefits. We note that this project is actually located in Southwestern Wyoming right near the Utah border. However, because it lies outside of the constraint that is alleviated by the Aeolus to Bridger transmission segment it was valued as a Non-Wyoming resource.

PacifiCorp scored these bids using the same methods as the Wyoming bids. The ranking of the offers did not change depending on the scoring method used and the non-price scores of the bids were not a factor (i.e., they did not change the ultimate project rankings).

In terms of bid selection, PacifiCorp recommended selecting all projects except the [redacted]. This selection is shown in Figure 2.

[redacted]

Source: PacifiCorp, 2017R RFP –Non-Wyoming Initial Short List Update – 2017-11-06 V6.pptx

PacifiCorp made this selection in order to achieve a balance of PPAs and BTAs. In addition, there was a reasonable gap between the last bid selected and the rejected [redacted] bid. We agreed with this conclusion.

REDACTED

B. INITIAL SHORTLIST

PacifiCorp placed the following projects and bidders on the Initial Shortlist. Again, if a project was selected to the Shortlist, then all bid options from a project were selected.

Table 9: Initial Shortlist

[redacted]

VI. BID REVIEW AND PRICE UPDATES

Best and Final Offers from all offers on the Initial Shortlist were due on November 22, 2017. Most bidders took advantage of the opportunity to adjust their pricing. Shortly thereafter it became clear that some form of tax reform legislation would soon be passed by the Federal Government. After discussions with the IEs, PacifiCorp sent a notice to all remaining bidders informing the bidders that, once tax reform legislation was finalized, bidders would be allowed a brief opportunity to refresh their offers to reflect any changes they felt necessary. This opportunity was extended to all bidders since parties could not be sure how the final law changes would affect each bidder.

On December 18th after conference committee approval of the "Tax Cuts and Jobs Act," PacifiCorp notified bidders that they could revise their offers by December 21 to reflect any changes they thought necessary as a result of the Act. Several bidders took advantage of the opportunity to adjust their offers.

PacifiCorp made other adjustments to the offers as well. As described in the RFP, PacifiCorp engaged a third-party consultant (Sapere Consulting) to review wind generation data from each offer in order to assess the reasonableness of data provided by the bidders. This was done in accordance with Guideline 10(f) in Commission Order 14-149. Evaluations were completed by November 17, 2017. Sapere Consulting found that most offers had reasonable output estimations. The exceptions were [redacted] and [redacted] bids, which each were subject to an 8% reduction in their net capacity factors based on the consultant's findings.

In addition, PacifiCorp found that the offers from [redacted] had mistakenly omitted Wyoming sales taxes in their offers. In order to perform production cost modeling the Company adjusted their levelized cost models to reflect these developments. Adjusting for (a) offer repricing, (b) capacity factor adjustments for [redacted] offers, (c) inclusion of sales taxes in [redacted] offers, and (d) some revisions in interconnection costs, resulted in the following changes in net benefits for all Wyoming shortlisted offers.

[redacted]

[redacted]

Table 10 shows that almost all bids saw the net benefits of their offer reduced. In some cases this was because the bidder raised their offer price. [redacted], for example, did this for several of their offers. In the case of BTAs, net benefits were reduced due to the lowering of the corporate tax rate, which lowered the value of the PTC. Other bidders, for example, [redacted]s [redacted] project and [redacted] [redacted] Project, left their offers relatively stable and saw little change in their valuations.

The non-Wyoming offers saw similar changes as shown in Table 11.

Table 11: Non-Wyoming Price Updates[6]

[redacted]

Putting together both lists, the table below shows the top offer for each project according to PacifiCorp's net benefits calculation.

Table 12: Top Offers for Each Project

[redacted]

The top offer, by net benefits, was the [redacted] PPA, followed by the [redacted] PPA, the [redacted] PPA, and the [redacted] and [redacted]. Note how close the offers are in price, with six projects net benefits in the $22-$27/MWh range.

One issue that we note here is that PacifiCorp initially requested letters of commitment from shortlisted bidders. During this process, PacifiCorp had objections to some of the forms of

[6] Note that two bid options for the [redacted] were removed from consideration due to the fact that the bidder was not able to hold to their promised on-line date as a result of delays in turbine manufacturing.

commitment provided by bidders, while some bidders' financial backers objected to providing such a letter of credit, since the letter compelled them to set aside collateral. Parties ultimately decided to interpret the RFP rules as requiring credit commitments only 20 days after selection to the Final Shortlist. We felt this was a reasonable compromise as it allowed PacifiCorp to continue with the evaluation and select the best offers from a wide range before getting into a discussion of what forms of collateral they would accept.

VII. FINAL SHORTLIST MODELING

A. INITIAL MODELING

To develop a Final Shortlist, bids on the Initial Shortlist were screened using the System Optimizer Model ("SO Model"). The SO analysis involved PacifiCorp creating a "base case" by dispatching the system without new wind additions and the D2 Segment over a 20-year time frame. The model added resources over the years in order to maintain a given reserve margin.

PacifiCorp then allowed the SO model to run again, this time allowing it to select a combination of bids from the shortlisted offers that would minimize costs, including the D2 Segment, to ratepayers. One key assumption here was the amount of new supply from inside the constrained area in Wyoming that would be enabled with the construction of the D2 segment. PacifiCorp initially assumed 1,030 MW would be available but ultimately, as discussed later in this report, decided that 1,270 MW could be incorporated onto the system with the addition of the D2 Segment.

The SO Model can only analyze the least-cost resource choice under one scenario or "path" of natural gas prices and CO_2 emissions costs at a time. PacifiCorp used three "paths" of natural gas prices (high, medium and low). Medium natural gas price assumptions were based on PacifiCorp's December forward price curve while high and low sensitivities were based on consultation with third-party experts. The SO model also used three "paths" of CO_2 costs (high, medium, and zero). The "medium" scenario started at $4.49/ton in 2030, rising to $7.95/ton in 2036 while the "high scenario" started at $3.62/ton in 2026 and rose to $19.23/ton in 2036.

Taken together these three gas and three CO_2 scenarios presented a total of nine specific "price-policy" scenarios.

These nine cases produced just two distinct portfolios. The full analysis provided to the IEs in January can be found in Attachment Two.

1. Under all scenarios the SO model selected the [redacted] bid, the [redacted] Bids, the [redacted] bid and the [redacted] bid. ("Portfolio A")[7]
2. In the medium gas, high CO2 case and in all three "high gas" cases the model also selected the [redacted] PPA. ("Portfolio B")

All selected portfolios showed net benefits as compared to the base case, ranging anywhere from $198 million to $782 million on a net present value basis. Benefits increased as gas prices and emission costs increased.

Once the SO Model was run, the Company passed along these two distinct portfolios to be assessed for stochastic risk. The term stochastic refers to assumptions being randomly varied along a given distribution using a Monte Carlo method. Assumptions for five factors were tested. Those five assumptions were load (electric demand), natural gas commodity prices, wholesale electricity prices, hydro generation availability, and thermal generation availability. Each portfolio was again assessed under the three CO_2 price cases and three gas price paths.

The stochastic analysis was performed with the Planning and Risk ("PaR") Model. The assumptions were randomly varied to result in 100 model runs for each case. This resulted in 100 different estimates of the cost –as measured by the present value of the revenue requirement, or PVRR, over 20 years – for each case. The average (mean) of these 100 estimates was provided as was the "risk-adjusted" mean which was equal to the average value plus the cost for the case at the 95th percentile times 5 percent.

[7] Note that this run was prior to the discovery that [redacted] offer had omitted Wyoming sales taxes. Subsequent analysis incorporated this cost and resulted in the selection of the [redacted] offer.

Table 13: Modeling Results

Natural Gas Cost	CO2 Cost	Portfolio	SO Model PVRR(d) (Benefit)/Cost ($m)	PaR Mean PVRR(d)	PaR Risk-adjusted PVRR(d)
Low	Zero	A	($198)	($153)	($161)
Low	Medium	A	($229)	($162)	($170)
Low	High	A	($347)	($306)	($323)
Medium	Zero	A	($372)	($319)	($335)
Medium	Medium	A	($399)	($349)	($367)
Medium	High	B	($493)	($445)	($467)
High	Zero	B	($704)	($572)	($601)
High	Medium	B	($720)	($604)	($634)
High	High	B	($782)	($689)	($724)

Table 13 above shows that the stochastic analysis reduces benefits somewhat, but benefits remain in each case.

The third step in the selection of the Final Shortlist was to use the SO Model to assess how the cost of the two portfolios from the stochastic risk assessment vary with different assumptions about fuel price and CO_2 compliance costs. Recall that, unlike the PaR model, the assumptions in the SO Model are defined outright, not varied along a distribution. Unlike the first step, where the SO Model was allowed to pick the ideal portfolio, in this analysis, each portfolio is fixed, allowing the model to dispatch the resource as part of the portfolio. The purpose of this step is to gather another data point regarding the risk of each portfolio. The result is an estimate of how much a portfolio costs under less than ideal circumstances (i.e., when key risk factors do not move in its favor). The results of this analysis are presented in Table 14. Note that table this does not include some costs for transmission improvements for Portfolio B that PacifiCorp added after the fact, such costs tilted the selection to Portfolio A in the low and medium gas scenarios.

Table 14: Scenario Modeling Results

Natural Gas Cost	CO2 Cost	Portolio A Benefits ($m)	Portfolio B Benefits ($m)
Low	Zero	($198)	($170)
Low	Medium	($229)	($216)
Low	High	($347)	($359)
Medium	Zero	($372)	($379)
Medium	Medium	($399)	($407)
Medium	High	($493)	($493)
High	Zero	($692)	($704)
High	Medium	($709)	($720)
High	High	($770)	($782)

This table shows that both portfolios produce positive benefits but that the portfolio with more wind is slightly more beneficial in higher gas price scenarios. This outcome make sense since the cost of wind stays the same but the cost of other resources increases. Therefore, more wind would generally be preferable in high gas price scenarios.

B. IE SENSITIVITY

We were somewhat surprised by the fact that the SO model would choose projects that had lower net levelized net benefits than other resources. Typically, we would expect resource selection to mirror the levelized cost analysis and, therefore, expected to see the [redacted] and [redacted] PPAs selected before the Benchmark projects.

We questioned PacifiCorp regarding this outcome. One item that they identified as a possible driver in the bid selection was the fact that, in order, to create the inputs for the SO model, bid costs were levelized but any PTC benefits were not—that is, these credits were flowed through as they were earned. Moreover, the SO Model covers the time period through 2036. Combined, these two factors meant that the SO Model spread the PTC benefits within the period of study, instead of over a 30-year period as is done in the Company's levelization models. This means that any offers earning PTCs would look more attractive than a levelized cost model would otherwise indicate.

To see if this was the case, we asked the Company to run the SO Model with medium gas price and CO_2 inputs and levelize PTCs over the 30-year life of BTA and Benchmark bids, instead of treating them as earned. The results were more in line with the levelized cost models. The SO model selected the [redacted] PPA, the [redacted] PPA, and the [redacted] project.

At this point, PacifiCorp made the observation that the non-levelized PTC selection would more closely reflect how they planned to pass PTC benefits through to ratepayers. While this was a reasonable assertion, we also noted that we had some concern that costs for their selection would not be levelized in real life but would, in fact, be front-loaded as well due to the way in which the costs for rate-based assets are recovered. Therefore, we had some concern that the front-loaded nature of rate recovery would cancel out the front-loaded benefits of the PTC recovery, and that the PPA-heavy portfolio was truly a better selection.

In response to this concern PacifiCorp produced an analysis looking at the actual flow of cost recoveries, treating both PTCs and costs as incurred. The table below compares the two portfolios, PacifiCorp's selected offers (PAC Portfolio) versus the PPA-heavy portfolio. Even though the SO Model only covers through 2036 PacifiCorp extended the analysis out through the 2050 – the end of the BTA project's useful life – by assuming market energy prices would simply increase with inflation each year after 2036. Note that PacifiCorp did not assume that any new supply replaces expiring contracts.

Table 15: Comparison of benefits ($m)

	Annual Benefit		Cumulative Benefit	
Year	PAC Portfolio	PPA Portfolio	PAC Portfolio	PPA Portfolio
2017	($0)	($0)	($0)	($0)
2018	$0	$0	($0)	($0)
2019	($0)	($0)	($0)	($0)
2020	$7	$13	$5	$10
2021	$58	$46	$46	$42
2022	$40	$38	$73	$68
2023	$22	$31	$87	$87
2024	$1	$20	$88	$98
2025	($17)	$5	$78	$101
2026	($25)	$4	$65	$103
2027	($34)	($3)	$49	$102
2028	($57)	($20)	$24	$93
2029	($88)	($52)	($13)	$71
2030	($96)	($78)	($51)	$41
2031	($0)	($79)	($51)	$12
2032	($4)	($82)	($53)	($16)
2033	($19)	($97)	($59)	($48)
2034	($31)	($109)	($68)	($80)
2035	($41)	($141)	($80)	($120)
2036	($56)	($156)	($95)	($161)
2037	($30)	($108)	($102)	($188)
2038	($36)	($114)	($110)	($214)
2039	($42)	($120)	($119)	($240)
2040	($49)	($126)	($129)	($265)
2041	($20)	$39	($133)	($258)
2042	($25)	$37	($137)	($251)
2043	($30)	$35	($142)	($245)
2044	($34)	$34	($147)	($240)
2045	($38)	$32	($153)	($236)
2046	($41)	$31	($158)	($231)
2047	($42)	$30	($163)	($228)
2048	($40)	$30	($168)	($224)
2049	($46)	$28	($173)	($221)
2050	($484)	($28)	($223)	($224)

While the PPA portfolio is more expensive in the early years, as we might assume since the value of the PTC in a PPA is spread out over a longer period of time, by 2034 it has greater cumulative benefits than PacifiCorp's selected portfolio. Even over the entire lifetime of all projects, the PPA portfolio produced more net benefits. Note also that the only reason the PacifiCorp portfolio was even close in net benefits over the entire time period was due to a large terminal value applied to company-owned bids totaling about $374 million in 2050. Without the terminal value the PPA portfolio produced a net cumulative benefit of $219 million versus $185 million for PacifiCorp's chosen portfolio.

C. INTERCONNECTION ANALYSIS

At this point we believed that the PPA-heavy portfolio should be the top choice. However, when we voiced this opinion to the Company they claimed that they had concerns regarding interconnection costs for some of the offers.

Specifically, the original system impact studies for most bids assumed completion of Gateway West and South projects by 2024. Because the Company had decided to move up the completion date for the D2 Segment they had a concern that projects located farther back in the interconnection queue would only be feasible to come online with the entire Gateway West and South projects complete.

As background, PacifiCorp's transmission arm, which assesses interconnection costs, must, by law, assume that each queue project is interconnected in order received so each project assumes that all projects ahead of it in the queue are interconnected. As more projects in the Wyoming area are interconnected it puts more strain on the transmission system until eventually major upgrades such as the Gateway West and South projects are needed.

Based on this analysis PacifiCorp believed it was highly unlikely that projects higher up in the queue would be able to interconnect with the D2 Segment alone. [redacted] was one such project, as was PacifiCorp's McFadden Ridge Project. The [redacted], and [redacted] projects were noted to have low queue positions and would likely be safe.

The Company said that PacifiCorp transmission was in the process of restudying interconnection costs assuming the accelerated completion schedule for the D2 Segment. At the end of January PacifiCorp transmission issued revised system studies. PacifiCorp transmission found that the Project with Queue number 713 triggered the need for major upgrades, stating: "Additionally, the Q0713 project triggers the need for the Transmission Provider's planned Energy Gateway South project. This project consists of a new 400 mile 500 kV transmission line from the planned Aeolus substation in Wyoming to the Transmission Provider's existing Clover substation in central Utah, with ancillary improvements." (See Attachment Three, page 8)

This meant that, in effect, any bid within the constrained area in Wyoming with a higher queue number than 712 would require extensive new transmission investment to be deliverable and likely would not be deliverable by the end of 2020. To see the effect on bids we can return to our earlier table showing the best offers from each project. Again, any offers higher than 712 located in the constrained area in Wyoming would need the completion of the Gateway South Project.

[redacted]

[redacted]

From this table we see that based on this analysis a majority of offers are no longer viable without major transmission investment. The [redacted], [redacted] and [redacted] projects are only viable because they are outside the constrained area in Wyoming. Inside the constraint only three projects – [redacted], [redacted], and [redacted] – are viable.

PacifiCorp claimed that this was why they proposed in their initial RFP that bids must have a completed system impact study; however, such a requirement would not have solved this issue. The fact is that even for projects that had completed system impact studies at the time of bid submission, those studies needed to be redone to account for the accelerated completion schedule for the D2 Segment. And, once those studies were redone, the same result would have occurred: projects with queue positions above 713 would have been effectively eliminated from further consideration.

To its credit, PacifiCorp dropped pursuit of McFadden Ridge after this analysis. However, these restudies showed more transfer capability from the constrained area than PacifiCorp had been assuming. Earlier studies assumed about 1,030 MW of new supply was enabled by the D2 Segment but PacifiCorp revised the number to 1,270 MW based on the sum of the wind projects in the constrained area that could be accommodated prior to Gateway South improvements.[8] With this revision, PacifiCorp stated that the larger Ekola Flats project was now selected as part of the optimal portfolio in the SO Model. Prior to this revision Ekola was not selected because, at 250 MW, there was not enough transfer capability to accommodate it.

The net result of these adjustments calls for consideration of the overall context of the RFP. Recall that in its RFP as originally drafted, PacifiCorp proposed to select only projects from the constrained area and offered three Benchmark projects. Based on the final analysis laid out above, only one other third party bid on the shortlist (the [redacted] project) could even compete with these offers. In fact, only one other Wyoming wind offer – the [redacted]

[8] Specifically, the company assumed Q542 (240 MW), Q706 (250 MW), Q707 (250 MW), Q 708 (250 MW), Q 712 (520 MW) could be accommodated for a total of 1,510 MW of interconnection capability. PacifiCorp then subtracted 240 MW to account for a customer that already has an executed interconnection agreement, leaving a total of 1,270 MW.

wind proposal – had a high enough queue position to be viable. So this entire RFP really boiled down to two viable benchmarks and two third-party offers, meaning a lot of the analysis presented here was of questionable value.

To be clear, the remaining viable offers were competitive offers, but were not the best the market could provide based on cost or risk, but for the transmission constraint issue. We understand and appreciate PacifiCorp's position and do not disagree with their transmission department's findings (beyond noting the obvious fact that many projects will likely drop out of the queue and that actual interconnection costs will differ from projected). To go forward with projects that cannot meet the proposed online date without major accelerated transmission investment would not seem to be the wisest course of action

The real issue here is that PacifiCorp's procurement (in the form of this RFP) got out ahead of its resource and transmission planning. If PacifiCorp had identified this plan earlier, then all aspects of this work (IRP, transmission planning and resource acquisition) could have worked together in a more coherent fashion.

D. REVISED FINAL SHORTLIST ANALYSIS

Based on these findings PacifiCorp completed additional analysis to confirm the Final Shortlist selection. PacifiCorp updated their analysis to remove all non-viable offers, update interconnection costs, increase transfer capability from the D2 Segment and adjust the Invenergy offer to include Wyoming sales taxes. The updated presentation is included here as Attachment Four.

With these revisions, the SO Model selected a portfolio that included the Benchmark TB Flats I and II bid, the Ekola Flats benchmark, the Cedar Springs BTA/PPA, and the Uinta BTA. Benefits generally increased due to the larger amount of total supply selected (as the 109 MW McFadden project was replaced by the 250 MW Ekola Flats project).

Again, the outcome was not surprising given the fact that there were so few bids to choose from and that, with the revised and increased costs for the Invenergy bid options, the Benchmark options generally were lower cost.

E. OTHER SENSITIVITIES

Along with the analysis described above PacifiCorp also provided additional sensitivities, including a solar sensitivity and a wind repowering sensitivity. The goal of each analysis was to ensure that other procurement activities did not lessen the benefits of this procurement.

For the solar sensitivity PacifiCorp ran the SO Model for two scenarios: (a) medium gas and medium CO_2 prices and (b) low gas no CO_2 prices. PacifiCorp looked at value of adding about 1,000 MW of new solar PPAs (a) instead of the shortlisted bids from the RFP and (b) along with the shortlisted bids. Prices and quantities were based on initial results from PacifiCorp's current solar RFP.

In all cases the combination of solar and shortlisted resources provided more net benefits. For example, in the medium gas medium CO_2 scenario benefits of just solar were $343 million on net whereas solar and the shortlisted bids provided $647 million of net benefits in the SO Model. In the low gas zero CO_2 scenario solar PPAs alone provided $196 million of net benefits but $312 million when combined with the shortlisted offers.

In the wind repowering scenario PacifiCorp allowed additional repowering of existing units up to their large generator interconnection agreement ("LGIA") limits. Running the same scenarios as with the solar sensitivity PacifiCorp found that benefits increased when repowering was added to the shortlisted bids. For example, in the medium gas medium CO_2 scenario benefits increase to $608 million on net versus $405 million with just the Final Shortlist offers alone.

PacifiCorp also provided a sensitivity which tried to account for the fact that the turbines used by the [redacted] might require the installation of a synchronous condenser or other equipment at the Aeolus substation to address performance issues. PacifiCorp ultimately determined that upgrade costs would have to be in the [redacted]

[redacted]. It was PacifiCorp's judgment that costs would not be higher than this level.

Finally, per our request, PacifiCorp looked at the as-earned costs and benefits of the Final Shortlist portfolio versus a portfolio in which the Cedar Springs PPA/BTA bid was replaced [redacted]. Our reason for requesting this was that we wanted to see if, as we found before, the actual recovery of costs and benefits truly favored the full PPA option.

PacifiCorp calculated costs and benefits under the medium-gas medium CO_2 cost scenario for each portfolio as they had done before, looking at as-earned costs and benefits and extending the analysis out to 2050 by assuming that energy benefits increase with inflation. They found that their preferred portfolio had a cumulative net benefit of $298 million on a net present value basis and the portfolio with [redacted] had a value of $280 million on a net present value basis. Removing the terminal value brings the numbers closer together, but the company's preferred portfolio still has a greater net benefit, $255 to $250 million on a net present value basis.

We do note that the portfolio with [redacted] has a lower cumulative net benefit from about 2033 through 2048, better risk protections, and offers the Company future flexibility, making it a reasonable choice. However, given the fact that the total net benefits favor PacifiCorp's selection we cannot conclude that the selection of the BTA/PPA bid is unreasonable.

VIII. CONCLUSIONS AND RECOMMENDATIONS

We recommend that the Commission acknowledge PacifiCorp's Final Shortlist. The bids do represent the top viable offers and are projected to provide net benefits. With proper risk mitigation the offers can provide value to ratepayers. While it is our understanding that the 2017 IRP is approved, we have yet to see a final approval order and are unaware of any potential conditions that may come with the approval order. For the purposes of this report, we assume there are no conditions that alter our recommendation here.

A majority of the selected offers here are BTAs and Benchmark resources. These bids offer at least two risks that are not generally present in power purchase agreements: (a) the risk of capital and operating cost overruns and (b) failure to claim the full value of the Production Tax Credit. Some of these risks can and will be managed in the BTA and EPC contracts the company will sign, but the protection will not be as strong as in a PPA. Developers can promise to deliver PTC complaint equipment and install by a certain time, but, several of these projects are dependent on PacifiCorp's transmission arm completing the D2 Segment in order to achieve deliverability.

In order to achieve a level of risk protection similar to a PPA for ratepayers, PacifiCorp must guarantee that capital and O&M costs will not exceed the amounts forecasted here and that ratepayers will be credited the full PTC values projected here as well regardless of whether or not PacifiCorp has the taxable income to utilize the credits. For reference, we include the final cost projections for each resource from the Company here as Attachment Five.

To be clear these should be "hard" guarantees as would be found in a commercial contract. PacifiCorp should not be permitted to recover additional costs or not credit full value of the PTC due to force majeure or change in law events. The risk regarding the PTC is exceptionally important. As we have just seen with corporate tax reform (and the debate that took place prior to the law's passage in which the PTC was considered briefly for major overhaul), the value of the credit can change rapidly.

Again, the reason that the Company should take this risk without exception is that a commercial developer will take this risk in a PPA. By way of example, the *pro forma* PPA in this RFP has this to say about tax credits:

> ii. "Seller shall bear all risks, financial and otherwise throughout the Term, associated with Seller's or the Facility's eligibility to receive PTCs, ITCs or other Tax Credits, or to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes. The obligations of the Parties hereunder, including those obligations set forth herein regarding the purchase and price for and Seller's obligation to deliver Net Output, shall be effective regardless of whether the sale of Output or Net Output from

> the Facility is eligible for, or receives, PTCs, ITCs or other Tax Credits during the Term."[9]

A related risk that was not analyzed is the risk of cost overruns for the D2 Segment. Because there is no real competition for this service it is more likely that cost overruns would occur here. These cost projections are important because they are a major driver of selection in this RFP. If actual costs are higher it may turn out that a better solution would have been to select more supply from outside the constrained area in Wyoming. Therefore, PacifiCorp should also be held to its cost projection for the D2 Segment. The revenue requirement numbers used in this analysis are included in Attachment Six.

In addition, the selected portfolio contains mostly options to be owned by the company. As a result PTC benefits are projected to flow to customers for the first ten years of operation as incurred. However, after the end of the ten-year PTC window these credits disappear and costs increase. PacifiCorp currently projects a $125 million cost increase in 2031. If the Commission believes such an increase would be unreasonable they should consider enacting some form of rate mitigation efforts in the future.

Going forward, many of the issues in this RFP were primarily caused by the resource acquisition function getting ahead of the resource planning and transmission planning function. Soon after the PTC sunset was established at the end of 2015, PacifiCorp's IRP team should have begun to consider if this change would drive them to pursue more renewable supply. Earlier consideration of this fact could have spurred debate about the proposal and possibly achieved earlier IRP approval as well as earlier revision of transmission planning in system impact studies. As it was the process was rushed and ultimately very few bids could be called viable.

In the future parties should seek better alignment of all these functions. Other tax credits (e.g., the Investment Tax Credit) are also planned to sunset and PacifiCorp has more transmission investment planned. As the next IRP process gets started parties should be asking what schedule PacifiCorp plans to pursue. Will they pursue additional solar with the sunset of

[9] Draft PPA section 2.8

the ITC? Would it make sense to accelerate any other portions of the Gateway project? Earlier consideration of these questions can lead to better and more transparent outcomes for all.

Finally, from a bid analysis standpoint any future modeling should at least consider the effect of unleveling of tax credit benefits. As demonstrated in our requested sensitivities if the production cost modeling does not consider the entire life of an asset then leveled benefits can force a choice of a suboptimal offer.

Attachment One

Qualified Wyoming Wind Options

Attachment One 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.

Attachment Two

INITIAL FINAL SHORTLIST MODELING

Attachment Two contains confidential and 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 confidential information is available to parties who have signed a confidential agreement in this docket.

The Company requests special handling of the commercially sensitive information. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Attachment Three

INTERCONNECTION ASSESSMENT

Large Generator Interconnection
System Impact Restudy Report

Completed for

("Interconnection Customer")
Q0713

Proposed Point of Interconnection

Yellowcake – Antelope Mine 230 kV transmission line
(POI at approx.43.113 N, 105.425 W)

January 29, 2018

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1.0 DESCRIPTION OF THE GENERATING FACILITY

("Interconnection Customer") proposed interconnecting 350 MW of new generation to PacifiCorp's ("Transmission Provider") Yellowcake – Antelope Mine 230 kV transmission line (Point of Interconnection at approx. 43.113 N, -105.425 W) located in Converse County, Wyoming. The project ("Project") will consist of one hundred forty (140) GE 127 2.5 MW wind turbines for a total output of 350 MW. The requested commercial operation date is December 31, 2020.

The restudy of this Project is performed due to the staging of the Energy Gateway West project. Specifically, while the entire Gateway West project has a longer development timeline, the Aeolus-Bridger/Anticline D.2 segment of the project (500 kV segment from the planned Aeolus substation to the planned Anticline substation) now has an expected 2020 in-service date. The earlier availability of the D.2 segment materially changes certain modeling assumptions that could impact the cost or timing of the interconnection of certain projects whose previous studies depended on Gateway West in its entirety.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the Project "Q0713."

2.0 SCOPE OF THE STUDY

The interconnection system impact restudy shall evaluate the impact of the proposed interconnection on the reliability of the transmission system. The interconnection system impact study will consider Base Case as well as all generating facilities (and with respect to (iii) below, any identified network upgrades associated with such higher queued interconnections) that, on the date the interconnection system impact study is commenced:

(i) are directly interconnected to the transmission system;
(ii) are interconnected to Affected Systems and may have an impact on the interconnection request;
(iii) have a pending higher queued interconnection request to interconnect to the transmission system; and
(iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

This interconnection system impact restudy will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The study will also provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of the cost responsibility and a non-binding good faith estimated time to construct.

Based on the engineering judgement, the stability results for this project are not expected to change and hence the restudy of stability analysis was not performed.

3.0 TYPE OF INTERCONNECTION SERVICE

The Interconnection Customer has selected *Energy Resource (ER)* interconnection service.

4.0 DESCRIPTION OF PROPOSED INTERCONNECTION

The Interconnection Customer's proposed Generating Facility is to be interconnected through a new Point of Interconnection ("POI") substation between Yellowcake and Antelope Mine 230 kV substations. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Generating Facility to the Transmission Provider's system.

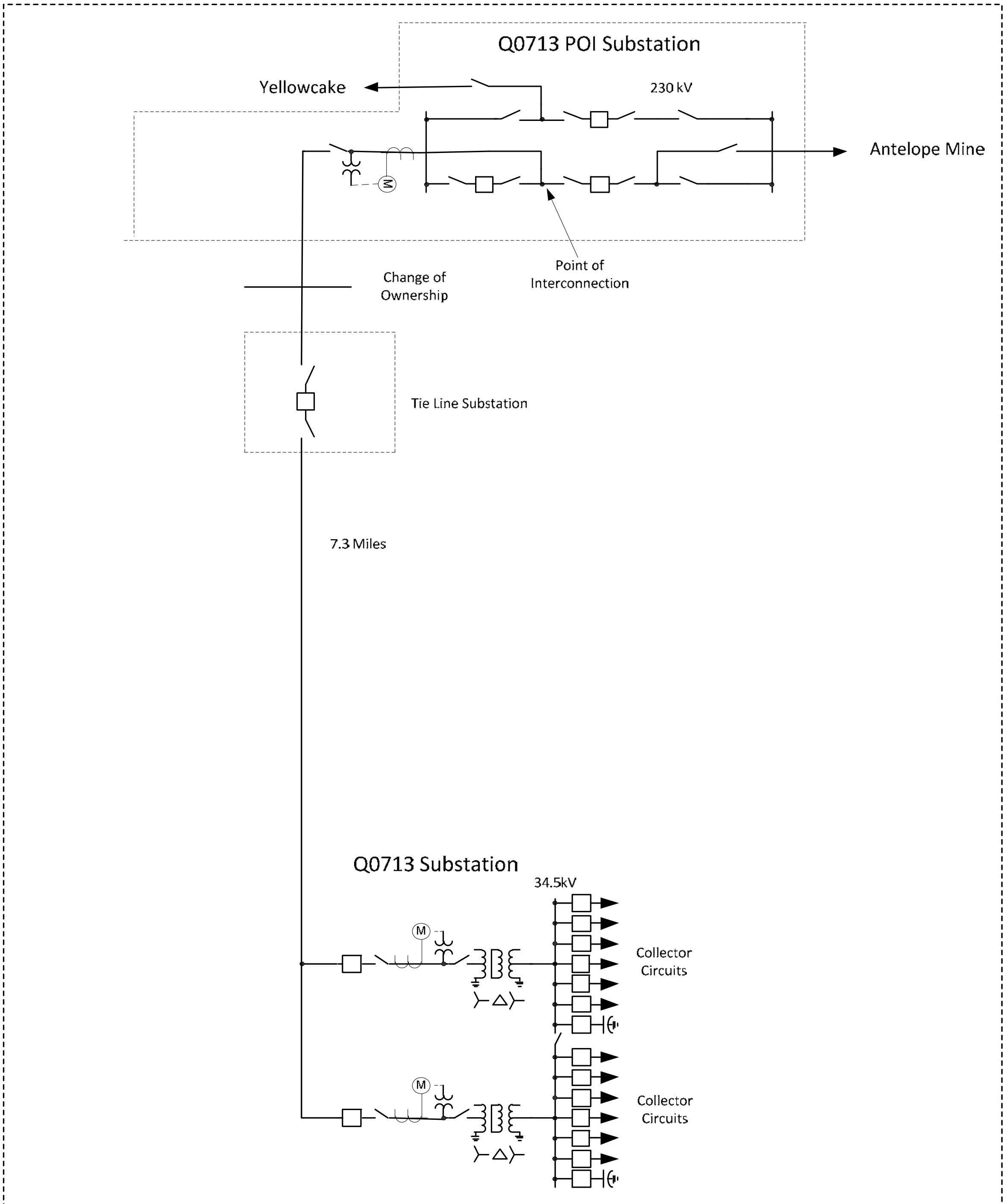

Figure 1: Simplified System One Line Diagram

5.0 OTHER OPTIONS CONSIDERED

The following alternative options were considered as potential points of interconnection for this Project: None

6.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests with an in-service date of December 2020 or earlier will be considered in this study and are listed in Appendix 1. If any of these requests are materially modified or withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: Interconnection Facilities associated with higher queued interconnection requests with an in-service date of December 2020 or earlier will be modeled in this study.
- The Interconnection Customer's request for energy or network resource interconnection service in and of itself does not convey transmission service. Only a Network Customer may make a request to designate a generating resource as a Network Resource. The provision of transmission service may require additional studies and the construction of additional upgrades.
- Under normal conditions, the Transmission Provider does not dispatch or otherwise directly control or regulate the output of generating facilities. Therefore, the need for transmission modifications, if any, which are required to provide Network Resource Interconnection Service will be evaluated on the basis of 100 percent deliverability (i.e., no displacement of other resources in the same area).
- This study assumes the Project will be integrated into the Transmission Provider's system at agreed upon and/or proposed POI.
- The Interconnection Customer will construct and own any facilities required between the Point of Change of Ownership and the Project unless specifically identified by the Transmission Provider.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and the Transmission Provider's performance and design standards.
- The Energy Gateway West, Aeolus-Bridger/Anticline D.2 500 kV line from the proposed Aeolus substation to the proposed Anticline substation and ancillary projects are assumed in service in 2020.
- All system improvements associated with the prior queued projects are in service before Q0713. This includes a new Aeolus – Shirley Basin #2 230 kV line with 2x1557 ACSR (Q0707), rebuild of the Standpipe-Freezeout-Aeolus 230 kV line to 2x1272 (Q0712), and rebuild of the Aeolus – Shirley Basin #1 230 kV line with 2x1557 ACSR (Q0712).
- All existing and proposed Remedial Action Schemes ("RAS") associated with prior queue generation facilities are assumed to be in service for this study.

- A RAS that will arm approximately 640 MW of generation for the Energy Gateway D.2 outages was assumed to be in-service.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Transmission Provider's web site regularly for Transmission System updates at http://www.pacificorp.com/tran.html

7.0 ENERGY RESOURCE (ER) INTERCONNECTION SERVICE

Energy Resource Interconnection Service allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System and to be eligible to deliver electric output using firm or non-firm transmission capacity on an as available basis.

7.1 Requirements

7.1.2 GENERATING FACILITY MODIFICATIONS

All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.

For synchronous generators, the power factor requirement is to be measured at the Point of Interconnection. For asynchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system in support of both voltage scheduling and contingency events that require transient voltage support, and must be able to provide reactive capability over the full range of real power output.

If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the Generating Facility must be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization from the Grid Operator is given to operate in other control mode (e.g. constant power factor control). The control mode of the generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating

Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, between 1.00 per unit to 1.04 per unit. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions. Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among generation facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.

For areas with multiple generating facilities additional studies may be required to determine whether or not critical interactions, including but not limited to control systems, exist. These studies, to be coordinated with Transmission Provider, will be the responsibility of the Interconnection Customer. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generating Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

To facilitate collection and validation of accurate modeling data to meet NERC modeling standards, PacifiCorp, as the Planning Coordinator, requires Phasor Measurement Units (PMUs) at all new Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater. In addition to owning and maintaining the PMU, the Generating Facility will be responsible for collecting, storing and retrieving data as requested by the Planning Coordinator. Data must be collected and be able to stream to Planning Coordinator for each of the Generator Facility's step-up transformers measured on the low side of the GSU at a sample rate of at least 30 samples per second and synchronized within +/- 2 milliseconds of the Coordinated Universal Time (UTC). Initially, the following data must be collected:

- Three phase voltage and voltage angle (analog)
- Three phase current (analog)

Data requirements are subject to change as deemed necessary to comply with local and federal regulations.

All generators must meet the Federal Energy Regulatory Committee ("FERC") and WECC low voltage ride-through requirements as specified in the interconnection agreement. As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Based on the turbine specification data provided by the Interconnection Customer, the wind turbines do not have the capability to deliver 100% of the power to the Point of Interconnection within the range of +/- 0.95 power factor. The data provided indicates that the wind turbines have a power factor capability of 0.98 capacitive and 0.96 inductive at rated power.

The study showed that the collector system injects approximately 17.2 MVAr (see Figure 3 in Appendix 3) when it is connected to the transmission system without the wind turbines being online. The Interconnection Customer will be required to ensure that there is minimum reactive interchange under these conditions and that the collector system of the Project is not contributing excessive reactive power into the system increasing voltage under light load conditions. Failure of the Project to minimize the reactive interchange under these conditions may result in the opening of the POI breakers for the Project by the grid operator.

At low output level, the Project needs to ensure that it maintains the power factor within +/- 0.95 at the POI and minimize the reactive power flow towards the transmission system to prevent high voltages. PacifiCorp has experienced high voltages in the Wyoming area when the transmission system is lightly loaded with low wind conditions. With low wind conditions the wind farms tend to supply reactive power into the transmission system increasing the voltage.

The Interconnection Customer is responsible for the protection of the transmission line between the Generating Facility and the Point of Interconnection substation. In order to provide this protection the Interconnection Customer shall construct and own a tie line substation to be located at the change of ownership (separate fenced facility adjacent to the Transmission Provider's Point of Interconnection substation) and include an Interconnection Customer owned protective device and associated transmission line relaying/communications. The ground grids of the Transmission Provider's Point of Interconnection substation and the Interconnection Customer's tie line substation will be connected to support the use of a bus differential protection scheme which will protect the overhead bus connection between the two facilities

7.1.3 Transmission System Modifications

- Construct a new POI substation with 3-breaker ring bus configuration between Yellowcake and Antelope Mine substations (refer to Figure 1).
- Expansion of the Windstar 230 kV substation with a new 230 kV bus.
- Addition of two new 230 kV breakers at Windstar substation.
- A new line termination at Windstar substation.
- A new line termination at Shirley Basin substation and one 230 kV circuit breaker.
- Construction of a new, 60-mile Windstar – Shirley Basin 230 kV line with 2-1272 ACSR (Aluminum Conductor Steel Reinforced).

Additionally, the Q0713 project triggers the need for the Transmission Provider's planned Energy Gateway South project. This project consists of a new 400 mile 500 kV transmission line from the planned Aeolus substation in Wyoming to the Transmission Provider's existing Clover substation in central Utah, with ancillary improvements.

7.1.4 TRANSMISSION REQUIREMENTS

Construct approximately 1,200 feet of 230 kV transmission line to loop-in the existing Antelope-Yellowcake 230 kV line to the Q0713 POI substation. This will require two guyed wood pole main line structures near structure 1/33 and a new guyed wood pole structure at each end of the POI sub.

Construct approximately 60 miles of 230 kV transmission line from Windstar substation to Shirley Basin substation. Conductor shall be double bundle 1272 ACSR "Bittern" Conductor.

The Interconnection Customer shall construct the tie line from the collector substation to the tie-line substation.

The Interconnection Customer is required to build tie-line substation adjacent to the new POI substation which will house the tie-line circuit breaker. The Transmission Provider shall review the design of the tie-line span between the tie-line substation deadend tower and the new POI substation deadend tower. The Interconnection Customer shall coil conductor, OPGW, shield wire, and line hardware with sufficient quantities to span between the tie-line substation tower and the POI substation tower.

The Transmission Provider will construct the span between the tie-line substation tower and the new POI substation tower.

If any Transmission Provider lines are crossed by Interconnection Customer tie-line, the Interconnection Customer line will cross under Transmission Provider's line with at least NESC plus 3 foot clearance under all sag conditions of both lines.

7.1.5 EXISTING CIRCUIT BREAKER UPGRADES – SHORT CIRCUIT

The increase in the fault duty on the system as a result of the addition of the Generating Facility with 140 GE 127 2.5 MW wind turbine generators fed through 140 – 2600 kVA 34.5 kV – 690 V transformers with 9.0% impedance then fed through two 230 – 34.5kV 120/115/200 MVA step up transformers with 8.0% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

7.1.6 PROTECTION REQUIREMENTS

The installation of protective relays for line fault detection will be required at the Transmission Provider's new 230 kV POI substation for the protection of the line to the Interconnection Customer's collector substation and the lines to Windstar and Teckla substations.

The ground mats of the tie-line substation and the Q0713 POI substation must be tied together so that metallic control cables can be used between the two facilities. Bus differential relays will be applied to detect faults on this connection. With this arrangement the Interconnection Customer must install line relays systems that will detect and clear all faults on the tie lines in 5 cycles or less. A set of non-pilot step distance line relays that will detect faults on the tie-line will also be applied at the Q0713 POI substation. Should the Interconnection Customer desire a potential alternative to the tie line substation in order to provide adequate protection to its tie-line, the Interconnection Customer may petition the Transmission Provider for an exemption to this arrangement. The Transmission Provider must review and approve the Interconnection Customer's proposed alternative. Without approval of the proposed alternative the tie-line substation configuration will be required. The Interconnection Customer will need to supply and maintain sets of line relays to be installed at Q0713 collector substation that will detect faults on the 230 kV line back to the Q0713 POI substation. These line relays can be time coordinated with the relays detecting faults on the transmission network and will not communicate with the line relays to be installed at the Q0713 POI substation for the tie-line.

Protective relay elements in the line relays at the Q0713 POI substation will monitor voltage and frequency. If the voltage, magnitude or frequency is outside of the normal operation range, this relay will trip the 230 kV breaker at the tie line substation.

The lines to Windstar and Teckla substations will continue to use permission over reaching logic line distance relays so the existing relays at Windstar and Teckla substations will require setting adjustments to accommodate addition of the POI substation.

The new 230 kV line between Windstar and Shirley Basin substations will be protected with a line current differential relay system.

7.1.7 Data (RTU) Requirements

Data for the operation of the power system will be needed from the Generating Facility and the new POI substation. The Interconnection Customer will install a Transmission Provider approved data concentrator at the collector substation and will install OPGW between the collector substation and tie line substation. The data will then be tied into a Transmission Provider owned RTU at the new POI substation.

In addition to the control and indication of the new 230 kV breakers at the POI substation, the following data will be acquired through the POI substation RTU. Also listed is the data that will be acquired from the collector substation.

From POI substation:
<u>Analogs:</u>

- Net Generation MW
- Net Generator MVAr
- Energy Register

From the Q0713 collector substation:
<u>Analogs:</u>

- Transformer 1 Real power
- Transformer 1 Reactive power
- Transformer 2 Real power
- Transformer 2 Reactive power
- 34.5 kV Real power 52 A1 & N
- 34.5 kV Reactive power 52 A1 & N
- 34.5 kV Real power 52 A2 & C
- 34.5 kV Reactive power 52 A2 & C
- 34.5 kV Real power 52 D
- 34.5 kV Reactive power 52 D
- 34.5 kV Real power 52 E
- 34.5 kV Reactive power 52 E
- 34.5 kV Real power 52 F
- 34.5 kV Reactive power 52 F
- 34.5 kV Real power 52 G
- 34.5 kV Reactive power 52 G
- 34.5 kV Real power 52 H
- 34.5 kV Reactive power 52 H
- 34.5 kV Real power 52 I
- 34.5 kV Reactive power 52 I
- 34.5 kV Real power 52 J
- 34.5 kV Reactive power 52 J
- 34.5 kV Real power 52 K
- 34.5 kV Reactive power 52 K
- 34.5 kV Real power 52 L & B1
- 34.5 kV Reactive power 52 L & B1
- 34.5 kV Real power 52 M &B2
- 34.5 kV Reactive power 52 M & B2
- 34.5 kV Reactive power 52 CAP 1
- 34.5 kV Reactive power 52 CAP 2
- A phase 230 kV transmission voltage
- B phase 230 kV transmission voltage
- C phase 230 kV transmission voltage
- Average Wind speed
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

<u>Status:</u>

- 230 kV Transformer Breaker 1
- 230 kV Transformer Breaker 2
- 34.5 kV breaker 52 A1 & N
- 34.5 kV breaker 52 A2 & C
- 34.5 kV breaker 52 D
- 34.5 kV breaker 52 E
- 34.5 kV breaker 52 F
- 34.5 kV breaker 52 G
- 34.5 kV breaker 52 H
- 34.5 kV breaker 52 I
- 34.5 kV breaker 52 J
- 34.5 kV breaker 52 K
- 34.5 kV breaker 52 L & B1
- 34.5 kV breaker 52 M & B2
- 34.5 kV breaker 52 CAP 1
- 34.5 kV breaker 52 CAP 2
- 34.5 kV breaker Bus Tie
- Line Relay Alarm

From the Tie Line Substation
Status:
- 230 kV Breaker

7.1.8 Substation Requirements

Q0713 POI Substation:
To support the requested interconnection, the Project will require a new 230kV, three breaker ring bus POI substation. The substation will be approximately 270’ x 470’ (fence dimensions) based on the Interconnection Customer provided facility requirements. The following is a list of the major equipment required for this Project:

- 3 – 230kV Power Circuit Breakers
- 6 – 230kV CCVTs
- 3 – 230kV CT/VT Metering units
- 13 – 230kV Switches
- 9 – 230kV Lightning Arresters
- 1 – 230kV SSVT
- 1 – Microwave Communication System

Q0713 Collector Station:
The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer’s Generating Facility for the Transmission Provider to install metering equipment. This area will share a fence and ground grid with the Generating Facility and have separate, unencumbered access for the Transmission Provider. AC station service for the

control house will be supplied by the Interconnection Customer. DC power for the control house will be supplied by the Transmission Provider.

Windstar Substation:
Install a new 230kV bay and line position to support a new 230kV line to Shirley Basin substation. The following major material will be required for this Project:

- 2 – 230kV Power Circuit Breakers
- 3 – 230kV CCVTs
- 5 – 230kV Switches
- 3 – 230kV Lightning Arresters

Shirley Basin Substation:
Install a new 230kV bay and line position to support a new 230kV line to Windstar substation. The following major material will be required for this Project:

- 1 – 230kV Power Circuit Breaker
- 3 – 230kV CCVTs
- 5 – 230kV Breaker Disconnect Switches
- 1 – Motor Operated Line Disconnect Switch
- 3 – 230kV Lightning Arresters
- 1 – Line Relay Panel
- 1 – Breaker Control Panel

7.1.9 Communication Requirements

The Interconnection Customer is required to install OPGW between the POI substation and the collector substation. ADSS fiber is required between the tie-line substation and the POI substation. The Interconnection Customer is to supply 2 - DNP3 circuits from the collector substation to the tie line substation and into the POI substation building with the SCADA points required.

Communications to the Transmission Provider's existing communications will be achieved through microwave. A new microwave communication system will be installed at the POI substation. The POI microwave will connect to the Transmission Provider's Flat Top communications site. The microwave tower at Flat Top will need to be replaced. The path will then connect to the Transmission Provider's Glenrock communications site and on through the existing system. The existing microwave between Glenrock and Flat Top will be upgraded to a 6 Ghz space diversity path.

Communication circuits are required between the POI, Windstar and Teckla substations over the new microwave. Multiplexes, routers and channel banks will be required at the POI, Teckla, and collector substations. At the POI substation a 48volt battery and charger is required for communication. At the collector substation the Interconnection Customer will supply AC voltage for the communication equipment.

7.1.10 METERING REQUIREMENTS

Interchange Metering

Point of Interconnection will be at the Transmission Provider Q0713 substation.

Metering will be designed bidirectional and rated for the total net generation of the Project. The bidirectional metering will also include the retail load (per tariff) delivered to the Interconnection Customer. The Transmission Provider will specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination 1000:5 CT/VT extended range for high accuracy metering.

The metering design package will include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One meter will be designated a primary SCADA meter and a second meter will be used designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data.

An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.

Q0713 Transformer A metering:

Revenue metering is required on the high side of the step-up transformers. The primary metering transformers shall be combination 230kV, 500:5 CT/VT extended range for high accuracy metering.

The Transmission Provider will design and procure the collector revenue metering panels. The panels shall be located inside the collector control house. The collector substation metering panel shall include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block. An Ethernet phone line is required for retail sales and generation accounting via the MV-90 translation system.

Q0713 Transformer B metering:

Revenue metering is required on the high side of the step-up transformer. The primary metering transformers shall be combination 230kV, 500:5 current ratio, CT/VT extended range for high accuracy metering.

The Transmission Provider will design and procure the collector revenue metering panels. The panels shall be located inside the collector control house. The collector substation metering panel shall include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block. An Ethernet phone line is required for retail sales and generation accounting via the MV-90 translation system.

Station Service/Construction Power

The Project is within the Transmission Provider service territory. Please note, prior to back feed Interconnection Customer must arrange transmission retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-625-6078 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.2 COST ESTIMATE (ER)

The following estimate represents only scopes of work that will be performed by the Transmission Provider. Costs for any work being performed by the Interconnection Customer are not included.

<u>Direct Assigned</u>	
Q0713 Collector substation	$1,218,000
Add metering and control house	
Q0713 POI substation	$837,000
Add POI terminal and metering	
Total Direct Assigned	**$2,055,000**
<u>Network Upgrade</u>	
Q0713 POI substation	$9,702,000
Add 230kV ring bus substation	
Yellowcake – Antelope Mine transmission line	$399,000
Loop transmission line in/out of POI substation	
Windstar to Shirley Basin 230kV line	$28,726,000
Build 60 miles of new 230 kV line	
Windstar substation	$4,194,000
Add new line position, update relay settings	
Shirley Basin substation	$2,120,000
Add new line position	
Flat Top substation	$904,000
Upgrade communications equipment	
Teckla substation	$48,000
Upgrade communications equipment, update relay settings	
Glenrock substation	$174,000
Upgrade communications equipment	
Total Network Upgrade	**$46,267,000**
Grand Total	**$48,322,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Generating Facility to Transmission Provider's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

7.3 SCHEDULE

The Transmission Provider estimates it will require approximately 60-78 months to permit, design, procure and construct the facilities described in the Energy Resource sections of this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report as well as the current anticipated in-service date of the Transmission Provider's Gateway South transmission line (2024) does not support the Interconnection Customer's requested Commercial Operation date of December 31,2020.

7.3.1 MAXIMUM AMOUNT OF POWER THAT CAN BE DELIVERED INTO NETWORK LOAD, WITH NO TRANSMISSION MODIFICATIONS (FOR INFORMATIONAL PURPOSES ONLY)

Zero (0) MW can be delivered on a firm basis to the Transmission Provider's network loads with additional transmission modifications.

7.3.2 ADDITIONAL TRANSMISSION MODIFICATIONS REQUIRED TO DELIVER 100% OF THE POWER INTO NETWORK LOAD (FOR INFORMATIONAL PURPOSES ONLY)

In order to deliver 100% of the power into Network Load, in addition to the mitigation identified in section 5.1.1.2, the completion of additional Transmission Provider Energy Gateway projects and other system improvements would also be required.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

Transmission Provider has identified the following affected systems: WAPA, Black Hills, Tri-State, and Basin Electric

A copy of this report will be shared with each Affected System.

9.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

9.1.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0542 (240 MW) – QF/NR
Q0706 (250 MW) – ER
Q0707 (250 MW) – ER
Q0708 (250 MW) – ER
Q0712 (520 MW) – ER

9.1.2 APPENDIX 2: PROPERTY REQUIREMENTS

Property Requirements for Point of Interconnection Substation

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Transmission Provider's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Transmission Provider's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Transmission Provider's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a Point of Interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's Project. The real property must be acceptable to Transmission Provider. Interconnection Customer will acquire fee ownership for interconnection substation unless Transmission Provider determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Transmission Provider's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Transmission Provider and are subject to the Transmission Provider's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the Project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Transmission Provider. The real property shall be a permitted or able to be permitted use in all zoning districts. The Interconnection Customer shall provide Transmission Provider with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Transmission Provider. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A

phase I environmental study is required for land being acquired in fee by the Transmission Provider unless waived by Transmission Provider.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Transmission Provider may require Interconnection Customer to procure various studies and surveys as determined necessary by Transmission Provider.

Operational: inadequate access for Transmission Provider’s equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Transmission Provider.

9.1.3 Appendix 3: Study Results

Power Flow Study Results

A Western Electricity Coordinating Council (WECC) approved 2015 Heavy Summer case was used to perform the power flow studies using PSS/E version 33.7. The 2015 Heavy Summer case was modified for the study.

Power flow studies were performed on both peak and off-peak load cases. The study was performed assuming the Energy Gateway D.2 Projects are in-service. The local 500 kV, 345 kV, 230 kV and 115 kV transmission system outages were considered during the study.

N-0 Results:
Under N-0 conditions with the Q0713 project in service there is a 101% overload on the Difficulty – Amasa 230 kV line. A new approximately 60-mile 230 kV line from Windstar to Shirley Basin constructed with 2- 1272 ACSR will mitigate this issue as well as some N-1 issues discussed below.

The data provided by the Interconnection Customer indicated that the generator does not have adequate reactive capability to deliver 100% of its power output at +/- 0.95 power factor. Hence, external shunt compensation which is dynamic in nature will be required in order to control the voltage and provide adequate reactive capability to maintain the voltage at the POI with a +/- 0.95 power factor on the high side of the step-up transformer.

Figure 3 below, shows injection of approximately 17.2 MVAr into the transmission system was observed if the collector system was connected with no generation from the Project. The addition of 17.2 MVAr on the transmission system under light load conditions could cause high voltages. The Project must control the voltage at the POI within the required voltage range provided by the Transmission Operator.

N-1 Results: Assuming Energy Gateway D.2 segment and the system improvements associated with the prior queued projects are in service, the following issues were identified.

- Outage of the Amasa – Difficulty-Shirley Basin 230 kV line overloads the Dave Johnston South Tap – Refinery Tap to 101%. Low voltages in the Spence – Buffalo Head area also observed. The new Windstar – Shirley Basin 230 kV line identified as mitigation under the N-0 results will resolve these issues.

- Outage of the Aeolus – Anticline 500 kV line, the Aeolus 230/500 kV transformer or the Anticline 345/500 kV transformer, post generation dropping of 640 MW (Aeolus RAS), results in multiple 230 kV line overloads. Construction of the Transmission Provider's planned Energy Gateway South 500 kV line from Aeolus to Clover, approximately 400 miles, will mitigate these issues.

N-2 Results: **N**o N-2 thermal or voltage issues were observed in the studies.

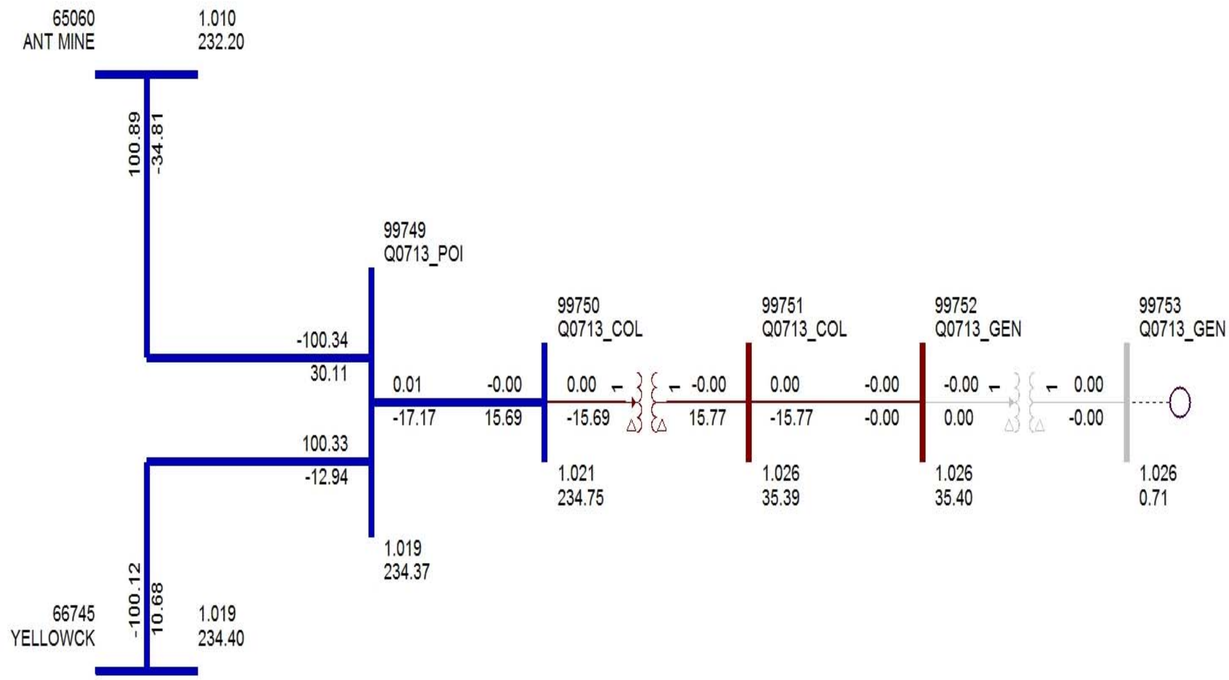

Figure 3: Charging from Q713 collector systems

Attachment Four

UPDATED FINAL SHORTLIST

Attachment Four contains confidential and 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 confidential information is available to parties who have signed a confidential agreement in this docket.

The Company requests special handling of the commercially sensitive information. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Attachment Five

FINAL COSTS FOR SHORTLISTED BIDS

Attachment Five 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.

Attachment Six

TRANSMISSION REVENUE REQUIREMENTS

Attachment Six 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.

Appendix A

BENCHMARK BID ANALYSIS

Appendix A contains confidential and 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 confidential information is available to parties who have signed a confidential agreement in this docket.

The Company requests special handling of the commercially sensitive information. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-2SR)
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 Surrebuttal Testimony of Rick T. Link

Utah IE Report

May 2018

Final Report of Merrimack Energy Group, Inc.

To

Utah Public Service Commission

PacifiCorp Renewable Request for Proposals

(2017R RFP)

Docket No 17-035-23 and Docket No 17-035-40

Public Version

February 2018

Merrimack

Energy

Table of Contents

I. Introduction

On January 16, 2018, in Docket No. 17-035-40, Rocky Mountain Power ("Rocky Mountain Power" or "Company"), a division of PacifiCorp[1] submitted "Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources" ("Application") to the Public Service Commission of Utah ("Commission") for approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource decision resulting from the PacifiCorp Renewable Request for Proposals ("2017R RFP"). In its application, the Company requested 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 the construction of the Aeolus-Bridger/Anticline line and network upgrades ("Transmission Projects") collectively, the ("Combined Projects"). The Company also provided supplemental testimony describing the results of the Company's 2017R Request for Proposals. In support of the Combined Projects, the Company concluded 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. Based on the results of the 2017R RFP, the Company sought 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 two of the benchmark facilities (TB Flats I and II, combined as a single project, and McFadden Ridge II), and two new facilities (NextEra Cedar Springs combined BTA/PPA proposal and Invenergy Uinta). The Company stated in its application that the results of the 2017R RFP and the extensive modeling that supports it confirms that the Combined Projects identified above are the least-cost, least-path available to serve the Company's customers by meeting both near-term and long-term needs for additional resources.

On February 16, 2018, Rocky Mountain Power submitted its Second Supplemental Direct Testimony on the results of the 2017 Request for Proposals ("RFP"), and its Motion to Deviate from R746-1-601(d)(i) and (ii) and from R746-1-203(1)(c). The second supplemental filing updates the 2017R RFP final shortlist to reflect the results of the interconnection restudy process and updated system impact studies ("SIS"). The updated 2017R RFP shortlist now consists of 1,311 MW, replacing the McFadden Ridge II benchmark resource, totaling 109 MW, with another company benchmark resource, Ekola Flats, totaling 250 MW. PacifiCorp also concluded that the revised portfolio provides increased benefits to customers due to the lower cost of the Ekola Flats project relative to the McFadden Ridge II project and the higher capacity associated with the Ekola Flats project.

Merrimack Energy Group, Inc. ("Merrimack Energy") was retained by the Public Service Commission of Utah to serve as the Independent Evaluator ("IE") for PacifiCorp's ("the Company") All Source Request for Proposals (RFP).[2] Utah Code Section 54-17-101 (known as the "Energy Resource Procurement Act") requires the Commission to appoint

[1] Throughout this report Rocky Mountain Power, the Company and PacifiCorp are used interchangeably.
[2] Merrimack Energy was originally retained to serve as Independent Evaluator for the Company's Request for Proposals for Flexible Resources ("RFP"), now referred to as the All Source RFP

an Independent Evaluator to monitor any solicitation conducted by an affected electrical utility under this chapter. Section 54-17-203 identifies the roles and requirements of the IE and specifies that the IE actively monitor the solicitation process for fairness and compliance with Commission rules. However, the IE may not make the decision as to which bid should be awarded under the solicitation.

Merrimack Energy's involvement as Independent Evaluator, therefore, began at the very initiation of the RFP development process and continued through final evaluation, selection, and is anticipated to continue through negotiations of the preferred proposal(s). The roles and functions of the Independent Evaluator in Utah are defined in the Energy Resource Procurement Act and in Rule R746-420-6. As defined, the overall objective of the Independent Evaluator is to ensure the solicitation process could reasonably be expected to be undertaken in a fair, consistent and unbiased manner.

The Scope of Work prepared by the Commission for the Independent Evaluator with regard to the final report identifies specific areas or issues that are required to be addressed in the final report:

1. An analysis of all aspects of the solicitation process and the IE's involvement, observations, conclusions and recommendations. The report will include an analysis of PacifiCorp's reasons and basis for:
    a. Evaluating and ranking bids and the benchmark options;
    b. Selecting a winning bid or benchmark option;
    c. Decisions regarding rejection of proposals or benchmark options are to be fully identified and detailed in the final report; and
    d. If the IE disagrees with PacifiCorp's ranking and conclusions, explain the basis and rationale for this disagreement.

2. At a minimum, the final report should also include an analysis of whether, or the extent to which:
    a. the energy resources selected are in the public interest and is the lowest reasonable cost to PacifiCorp's retail customers taking into consideration long-term and short-term impacts, risk, reliability, and the financial impact on PacifiCorp;
    b. the solicitation process was fair;
    c. the benchmark option was considered and evaluated in the same way as all other bids;
    d. screening factors and weights were applied consistently and comparably to all bid responses and the benchmark option;
    e. credit requirements, liquidated damage provisions, warranties, and other similar requirements affect the bid evaluations and the outcome of the solicitation process;
    f. all reasonable available data and information necessary in order for a potential bidder to submit a bid was provided to potential bidders;

g. all data, information, and models relevant to the solicitation process were made available or given access to the IE to permit full and timely testing and verification of assumptions, models, input, output, and results;
h. confidentiality claims and concerns between the IE and PacifiCorp were resolved in a manner that preserved confidentiality as necessary, yet permitted dissemination and consideration of all information reasonably necessary for an open bidding process to be conducted fairly and thoroughly validated;
i. evaluations were performed consistent with evaluation criteria and methods approved; and
j. negotiations between PacifiCorp and bidders proceeded in a timely fashion and were conducted in good faith.

3. The final report shall also offer, where necessary, feedback on the solicitation and solicitation process including:
    a. content of the solicitation;
    b. evaluation and ranking of bid responses;
    c. creation of a short list of bidders for more detailed analysis and negotiations;
    d. post-bid discussions and negotiations with, and evaluation of, short list bidders; and
    e. negotiation of proposed contracts with successful bidders.

The IE shall also provide recommendations with respect to changes or improvements for a future solicitation process.

In addition to the Final IE report, the IE was required to submit a Shortlist Report. The Shortlist Report was provided to the Commission, DPU and Company on February 15, 2018. The Scope of Work for the Final IE Report states that "to the degree there may be duplication between the reports required in Tasks B8 (IE Shortlist Report) and C1 (IE Final Report), the B8 Report may be simply referenced in the final report." While the majority of the body of the B8 Shortlist Report is also included in this report, Merrimack Energy is including references to supporting Appendices included in the Final Shortlist report rather than replicate the Appendices in the Final IE Report. It is important to note that all Appendices included in the IE Shortlist Report are Confidential Documents.

Merrimack Energy has been actively involved in PacifiCorp's 2017R RFP from the beginning and has been involved in the RFP development process and monitoring the solicitation process through participation in all major team meetings, conference calls and conversations regarding the decisions about the RFP and solicitation process. Our involvement has included all stages of the solicitation process, including (1) development of the RFP; (2) receipt and evaluation/selection of proposals; and (3) monitoring contract negotiations.[3] The objective of this involvement has been to ensure the process is fair and

[3] The IE is required to monitor the contract negotiation process. However, unlike previous PacifiCorp solicitations, the IE Final Report is due prior to the completion of the contract negotiation process due to the timeframe established for this solicitation.

unbiased and provides the best deal for consumers and to raise any concerns along the way, if necessary, to ensure the process stays on track to meet these objectives. [4]

For purposes of undertaking this assessment of the competitive solicitation or RFP process, the following issues will be addressed in this report:

1. An overview of the competitive bidding requirements in Utah which serve to guide the implementation of the bidding process;

2. A list and description of the Scope of Work of the Independent Evaluator as well as the actual activities undertaken by the IE relative to the tasks included in the Utah statutes;

3. A list of the criteria relied upon by the IE to assess the performance of PacifiCorp during the solicitation process;

4. Background to the regulatory decisions and processes leading up to request for approval of the selected resource.

5. A brief description of the contents of the RFP document, including the objectives of the RFP, requirements of the bidders, the proposed evaluation process, Code of Conduct and other information. This information is included for reference purposes with regard to the discussion of PacifiCorp's performance;

6. A brief description of the activities undertaken by the IE at each stage of the solicitation process;

7. Description and assessment of the entire competitive solicitation process including preparation for receipt of bids, bid evaluation and selection process for establishing the initial and final shortlist of preferred proposals and the initial negotiation process to address conditions associated with each short-listed proposal;

8. Description of the comments of shortlisted bidders regarding contract provisions, and the contract negotiation process;[5]

9. Assessment of PacifiCorp's performance in managing and implementing the process relative to the requirements outlined in the Utah Procurement

[4] It is important to note that the Company was ultimately responsible for all final decisions. The IE provided observations or input to the Company, Commission and Division as required.

[5] Unlike previous PacifiCorp RFP processes on which Merrimack Energy has served as IE, the schedule for this solicitation calls for the contract negotiation process to be on-going at the time the IE is required to submit its Final Report. Therefore, this Final Report will not provide a complete assessment of the contract negotiation process or assessment of the final contract as we have included in prior IE Final Reports.

Rules, key criteria for a fair and equitable solicitation process, and lessons learned from the process;

10. Conclusions and recommendations for improving the competitive bidding process.

II. Competitive Bidding Requirements in Utah

Utah Code Section 54-17-101, known as the Energy Resource Procurement Act (2005) requires that an affected electric utility seeking to acquire or construct a significant energy resource[6] shall conduct a solicitation process that is approved by the Commission. The Commission shall determine whether the solicitation process complies with this chapter and whether it is in the public interest taking into consideration whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electric utility located in the state.

Rule R746-420 outlines in detail the requirements of a solicitation process with regard to implementation of the Energy Resource Procurement Act. Among other issues, Rule R746-420 provides general provisions regarding the filing requirements for the soliciting utility in seeking approval of the solicitation, a description of the solicitation process and associated requirements, and the roles and responsibilities of an Independent Evaluator to oversee the solicitation process.

This Section of the Report will address three major issues. Sub-section A will provide a summary of the solicitation requirements in Utah as a means of setting the stage for a discussion of whether PacifiCorp effectively met the requirements of the Utah statutes. Sub-section B provides an overview of the required role of the Independent Evaluator in the process.

A. Solicitation Requirements in Utah

The specific requirements for the solicitation process are included in section R746-420-3 of the Rules. The key provisions and Disclosures by topic area in the rules are summarized below. In our assessment of PacifiCorp's solicitation process, adherence to these requirements will be a focus of our discussion. Chapter VIII includes that assessment based on 54-17-101 and R746-420.

(1) General Objectives and Requirements of the Solicitation Process

- The solicitation process must be fair, reasonable and in the public interest;
- Be designed to lead to acquisition of electricity at the lowest reasonable cost to retail customers in the state;

[6] A significant energy resource is defined as a resource that consists of a total of 100 MW or more of new generating capacity that has a dependable life of ten or more years.

- Consider long-term and short-term impacts, risk, reliability, financial impacts on the utility, and other relevant factors;
- Be designed to solicit a robust set of bids;
- Be sufficiently flexible to permit the evaluation and selection of those resources or combination of resources determined by the Commission to be in the public interest;
- Be timely in the sense of ensuring adequate time is allotted to undertake the analysis and secure the resources.

(2) ***<u>Screening Criteria – Screening in a solicitation process</u>***

- Develop and utilize screening and evaluation criteria, ranking factors and evaluation methodologies that are reasonably designed to ensure that the Solicitation Process is fair, reasonable and in the public interest in consultation with the IE and Division. Initial screening criteria can include cost to ratepayers, timing of deliveries, point of delivery, dispatchability/flexibility, credit requirements, and transmission, interconnection and integration costs and benefits;
- Allocation of project development risks, including capital cost overruns, fuel price risk and environmental regulatory risk among project developers, utility and ratepayers;
- Environmental impacts;
- In developing the screening and evaluation criteria, the utility shall consider the assumptions in the utility's most recent Integrated Resource Plan ("IRP"), any recently filed IRP update, any Commission Order on the IRP or IRP update and in its Benchmark Option;
- The utility may consider non-conforming bids

(3) ***<u>Screening Criteria – Request for Qualification and Request for Proposals</u>***

- The soliciting utility may utilize a Request for Qualifications (RFQ) process:
- The IE will provide each eligible bidder a bid number when the utility, in consultation with the IE has determined the bidder has met the criteria under the RFQ:
- Reasonable criteria for the RFQ could include such factors as credit requirements, non-performance risk, technical experience, and financial feasibility.

(4) ***<u>Disclosures – Benchmark Option Included</u>***

- Identify whether the Benchmark is an owned option or a purchase option
- If the option is a utility-owned option, provide a detailed description of the facility, including a description of the facility, fuel type, technology, efficiency, location, project life,

transmission requirements and operating and dispatch characteristics;

- Assurance from the utility that the Benchmark Option will be validated by the IE and that no changes to any aspects of the Benchmark option will be permitted after the validation of the benchmark option by the IE and prior to receipt of bids under the RFP and that the Benchmark Option will not be subject to change unless updates to other bids are permitted.

(5) <u>Disclosures – Evaluation Methodology</u>

- The solicitation shall include a clear and complete description and explanation of the methodologies to be used in the evaluation and ranking of bids including a description of all evaluation procedures, factors and weights, credit requirements, proforma contracts, and solicitation schedule.

(6) <u>Disclosures – Independent Evaluator</u>

- The solicitation should describe the role of the IE consistent with Section 54-17-203 including an explanation of the role, contact information and directions for potential bidders to contact the IE with questions, comments, information and suggestions.

(7) <u>General Requirements</u>

- The solicitation must clearly describe the nature and relevant attributes of the requested resources
- Identify the amounts and types of resources requested, timing of deliveries, pricing options, acceptable delivery points, price and non-price factors and weights, credit and security requirements, transmission constraints, etc.;
- Utilize an evaluation methodology for resources of different types and lengths which is fair, reasonable and in the public interest and which is validated by the IE;
- Impose credit requirements and other bidding requirements that are non-discriminatory, fair, reasonable and in the public interest;
- Permit a range of commercially reasonable alternatives to satisfy credit and security requirements;
- Permit and encourage negotiation with short-listed bidders to balance increased value and risk;
- Provide reasonable protection for confidential information.

(8) <u>Process Requirements for a Benchmark Option</u>

- Evaluation team may not be members of the Bid team or communicate with the Bid team about the solicitation process;
- The names and titles of each member of the Bid team, non-blinded personnel, and Evaluation team shall be provided to the IE;

- The Evaluation team shall have no direct or indirect communication with any bidder other than through the IE until such time as a final short list is selected by the Soliciting Utility
- Each team member must agree to all restriction and conditions contained in the Commission rules;
- All relevant costs and characteristics of the Benchmark option must be audited and validated by the IE prior to receiving any of the bids;
- All bids must be considered and evaluated against the Benchmark option on a fair and comparable basis;
- Environmental risks and weight factors must be applied consistently and comparably to all bid responses and the benchmark option;
- The Solicitation must allow power purchase contract terms equivalent to the projected facility life of the Benchmark Option. The Commission may waive this requirement.

(9) Issuance of a Solicitation

- The utility shall issue the solicitation promptly after Commission approval;
- Bids shall be submitted directly to the IE;
- The utility shall hold a pre-bid conference.

(10) Evaluation of Bids

- The utility shall provide all data, models, materials and other information used in developing the solicitation, preparing the Benchmark option, or screening, evaluating or selecting bids to the IE and the Division staff;
- The IE shall pursue a reasonable combination of auditing the utility's evaluation and conducting its own independent evaluation, in consultation with the Division;
- Communications with bidders should occur through the IE on a confidential or blinded basis;
- The IE shall have access to all information and resources utilized by the utility in conducting its analyses. The utility shall provide the IE with access to documents, data, and models utilized by the utility in its analyses;
- The IE shall monitor any negotiations with short listed bidders;
- The Division and IE may ask the PacifiCorp Transmission group to conduct reasonable and necessary transmission analyses concerning bids received.

B. Role of the Independent Evaluator

The Scope of Work for the IE is presented in several documents including the Request for Proposals for Consulting Services for the IE issued by the Commission, Utah statutes

(Section 54-17-101 and Rule R746-420), and RFP Appendix M (Role of the Independent Evaluator) in the 2017R RFP. The scope of work for the assignment requires the Independent Evaluator (IE) to participate in all three phases of the solicitation process: (1) Solicitation process approval; (2) Monitor solicitation process and (3) Energy resource decision. The specific tasks for the Independent Evaluator under each phase of the solicitation process are listed below. The specific tasks outlined guide the activities of the Independent Evaluator throughout the solicitation process.

1. Requirements Outlined for the IE

The requirements of the IE are summarized below for each stage of the process.

a. Solicitation Process Approval

1. Review PacifiCorp's proposed solicitation process to assure it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to PacifiCorp's retail customers taking into consideration long-term and short-term impacts, risk, reliability and the financial impacts on PacifiCorp.

2. Review PacifiCorp's proposed solicitation process to assure the evaluation criteria, methods and computer models are sufficient to evaluate the benchmark option and prospective bids in a manner that is fair, unbiased and comparable, to the extent practicable, and that the evaluation tools will be sufficient to determine the best alternative for PacifiCorp's retail customers.

3. Review the adequacy, accuracy and completeness of all proposed solicitation materials including bid evaluation templates, bidding documents (i.e. RFP, Bid Form or Response Package, and the proposed Contracts), disclosure of evaluation criteria (including financial and credit requirements), methods and modeling methodology to ensure the process is fair, equitable and consistent.

4. Review, analyze and validate potential benchmark options (including cost assumptions) for adequacy, accuracy, completeness, reasonableness, and consistency with the evaluation process.

5. Review and validate the adequacy and reasonableness of the proposed evaluation methods, any computer models used to screen and rank bids from initial screening to final resource selection (including spreadsheet screening models and production cost models), and input assumptions. This task requires an assessment of the extent to which the evaluation methods and models are consistent with accepted industry standards and/or practices and the appropriateness of any adjustments made for debt imputation are assessed. Provide input to the Soliciting Utility on the development of screening and evaluation criteria and evaluation methodologies.

6. Provide a written evaluation including recommendations to the Commission regarding the results of the above tasks. Include recommendations on approval of the proposed solicitation or modifications required for approval and the bases for recommendations.

7. Provide input on the development of screening and evaluation criteria, ranking factors, and evaluation methods. Ensure that screening and evaluation criteria take into consideration the assumptions included in PacifiCorp's most recent IRP, any recently filed IRP update, any PSC Order on the IRP or IRP Update, and in its Benchmark Option.

8. Testify before the Commission regarding approval of the proposed solicitation, if necessary.

b. Solicitation Process Bid Monitoring and Evaluation

1. Monitor, observe, validate and offer feedback to the Soliciting Utility, the Commission, and the Division of Public Utilities on all aspects of the solicitation process, including: (1) content of the Solicitation; (2) communications between bidders and PacifiCorp; (3) evaluation and ranking of bid responses; (4) selection of the "short list" of bidders for more detailed analysis and negotiation; (5) negotiations between short list bidders and PacifiCorp; (6) ranking of the final list of alternatives; (7) negotiations of the proposed contracts with successful bidders; and (8) selection of energy resource(s).

2. Provide input to the Soliciting Utility on: (1) the development of screening and evaluation criteria, ranking factors and evaluation methodologies to ensure the solicitation process is fair, reasonable and in the public interest; (2) the development of initial screening and evaluation criteria that take into consideration the assumptions included in the most recent IRP; (3) whether a bidder has met the criteria specified in any RFQ and whether to reject or accept non-conforming RFQ responses; (4) whether and when data and information should be distributed to bidders to facilitate a fair and reasonable competitive bidding process; (5) negotiation of proposed contracts with successful bidders; and (6) other matters as directed by the Commission.

3. Participate in the pre-bid conferences.

4. Following the pre-bid conference, and before the bids are due submit a status report to the Commission and the Division noting any unresolved issues that could impair the equity or appropriateness of the solicitation process.

5. Facilitate and monitor communications between the Soliciting Utility and Bidders.

6. Review and validate the assumptions and calculations of any Benchmark options.

7. Analyze the Benchmark option for reasonableness and consistency with the Solicitation Process.

8. Participate in the receipt of bids and "blind" bid responses.

9. Establish a webpage for information exchange between bidders and PacifiCorp.

10. Monitor all communications with bidders after receipt of bids and negotiations conducted by PacifiCorp and any bidders. Communications between a Soliciting Utility and potential or actual bidders shall be conducted through or in the presence of the Independent Evaluator.

11. Monitor and audit the evaluation process and validate that evaluation criteria, methods, models and other solicitation processes have been applied as approved by the Commission and consistently and appropriately applied to all bids. Audit the bid evaluations to verify that assumptions, inputs, outputs and results are appropriate and reasonable.

12. Advise the Commission, Division and PacifiCorp at all stages of the process of any issue that might reasonably be construed to affect the integrity of the solicitation process and provide PacifiCorp an opportunity to remedy the defect identified.

13. Periodically submit written status reports to the Commission and Division on the solicitation as directed by the Commission or as the IE deems appropriate.

14. File a report with the Commission and Division detailing the methods and results of PacifiCorp's initial screening evaluation of all bids. Include a description of the bids, selection criteria, and provide the basis for the selection of the short-listed bids and rationale for eliminating bids.

Also, upon advance notice to the Soliciting Utility, the IE may conduct meetings with intervenors during the Solicitation Process to the extent determined by the Independent Evaluator or as directed by the Commission. The IE shall also document all substantive correspondence and communications with the Soliciting Utility and the bidders.

c. Participation in the Energy Resource Decision Approval Process

1. File a detailed Final Report (confidential and public versions) with the Commission and provide a copy to the Division as soon as possible following the completion of the Solicitation Process. The Final Report shall include analyses of the Solicitation, the Solicitation Process, the Soliciting Utility's evaluation and selection of bids and resources, the final results, and whether the selected resources are in the public interest.

2. Participate in any Utah technical conferences related to the Energy Resource Decision Approval Process.

3. Participate in and testify at Commission hearings on approval of the solicitation process and/or approval of a Significant Energy Resource Decision.

Merrimack Energy performed all these functions as IE in this process. Examples of the specific functions undertaken by Merrimack Energy are described within the Report for each of the phases of the solicitation process. This Report is the Final Report required of the IE as described above.

III. Summary of the 2017R RFP Process and Key Provisions of the RFP

This Chapter of the Report will provide a high-level description of development and issuance of the 2017R RFP and the associated Appendices and Attachments.

PacifiCorp, d.b.a. Rocky Mountain Power ("PacifiCorp") notified the Public Service Commission of Utah of its intent to seek approval of a solicitation process under Part 2 of the Energy Resource Procurement Act, Utah Code Ann. Title 54, Chapter 17 on April 17, 2017. PacifiCorp indicated it anticipated filing its application for approval of its Request for Proposals for new wind resources on June 16, 2017. The 2017R RFP would solicit bids for up to 1,270 MW of wind resources capable of interconnecting to, and/or delivering energy and capacity across PacifiCorp's transmission system in Wyoming. To ensure eligibility for the full value of federal production tax credits, the 2017R RFP would seek bids that can achieve commercial operation no later than December 31, 2020.

On June 16, 2017, PacifiCorp (d/b/a Rocky Mountain Power) filed an application with the Utah Public Service Commission ("Commission") in Docket No. 17-035-23 requesting approval of a solicitation process for the 2017R RFP. The Application requests that the Commission issue an order approving the Company's 2017 Renewable Request for Proposals seeking up to approximately 1,270 of new wind resources capable of interconnecting to, and/or delivering energy and capacity across PacifiCorp's transmission system in Wyoming. A Scheduling Conference on the approval of the solicitation process was held on June 27, 2017, with a Scheduling Order issued by the Commission on June 28, 2017. PacifiCorp held a Pre-Issuance Bidders Conference on May 31, 2017, as required.

The scope of the draft 2017R RFP was focused on PacifiCorp attempting to capture a time limited resource opportunity arising from the expiration of the federal production tax credits ("PTC") through procurement of proposed wind resources in conjunction with a new 140-mile, 500 kV transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to a new annex substation, Bridger/Anticline, located near the existing Jim Bridger substation ("Transmission Project"). The combination of wind generation and the transmission option proposed was determined by PacifiCorp to have positive value to customers as identified in its 2017 Integrated Resource Plan ("IRP"). Bidders could submit proposals under the following structures: (1) Power Purchase Agreement ("PPA") with or without a purchase option provided to PacifiCorp; (2) Build-Transfer structure in accordance with the terms of an Asset Purchase and Sale Agreement ("APSA"), and (3) a Bidder-proposed ownership structure.

The initial draft of the 2017R RFP was provided to the IE and posted on PacifiCorp's website on or around June 16, 2017. The draft RFP provided a detailed description of the resource alternatives sought by PacifiCorp, the logistics for submitting a bid including the information, forms, and schedules required with each type of resource alternative proposed, a description of the bid evaluation process and a description of the evaluation criteria to be used to evaluate and select bids. The draft RFP contained seventeen Appendices. In addition, there were Forms in the document for bidders to fill out and submit with their proposal. Finally, the draft RFP contained a description of the role of the Independent Evaluator in the bidding process, and a Code of Conduct.

Subsequent to submission of the draft RFP, the IE prepared a list of questions regarding the RFP, objectives of the RFP and basis for the proposed approach and sent the questions to PacifiCorp for review.

Merrimack Energy staff and members of the Division staff met with PacifiCorp on July 19, 2017 to primarily observe the Code of Conduct training process for employees who are subject to the Code of Conduct as well as to discuss the evaluation methodology, models, and input assumptions to be used by PacifiCorp to prepare for the bid evaluation process. Prior to the meeting, the IE reviewed the RFP and related documents with PacifiCorp and raised a number of questions to PacifiCorp as well as providing comments on certain provisions in the RFP. PacifiCorp also noted that it had retained an IE in Oregon. Both IEs made suggestions regarding revisions to the draft RFP that PacifiCorp agreed to adopt.

Some of the primary revisions to the RFP proposed by Merrimack Energy that PacifiCorp indicated a willingness to review and assess in the draft RFP included the following:

1. Revised the schedule slightly to move the Notice of Intent to bid from September 6 to September 15, 2017 after the bidder's workshop on the 12th. The IE proposed this revision to provide an opportunity for bidders to assess whether to submit a Notice of Intent to bid until after it has had the opportunity to participate in the Bidder's workshop;

2. Revised the initial minimum requirement of requiring a system impact study to only demonstrating that the bidder has initiated the study phase of the interconnection process (i.e. signed agreement and paid deposit to begin feasibility study). Added a condition that the RFP would require a System Impact Study by the initial shortlist to confirm costs and that it can be interconnected to support a 12/31/2020 project commercial operation date;

3. Re-allocated the weights in the non-price table to put higher weighting on the transmission progress criteria;

4. Revised the requirement to meet 100% of the federal PTC to accept full or partial PTC still subject to the December 31, 2020 COD deadline;

5. Revised the Code of Conduct to reflect the presence of a self-build option consistent with other PacifiCorp RFPs for which there was a self-build or benchmark option. The IE notified PacifiCorp that the Code of Conduct initially included in the solicitation documents was from the 2016 All Source RFP which did not include a benchmark resource. Since this RFP included a benchmark resource, the IE suggested that PacifiCorp include a Code of Conduct that reflected the presence of a benchmark resource.

One of the requirements of the Commission's June 28, 2017 Scheduling Order was for the soliciting utility to provide data, information, and models to the IE pursuant to Utah Admin. Code R746-420-1(2).[7] According to the Scheduling Order, comments of the parties were due on Friday, August 4, 2017 and comments from the IE were due one week later on August 11, 2017. Reply comments of all parties were due on August 18th, with a requested Decision from the Commission on August 25, 2017.

Based on the schedule, several parties submitted comments on August 4, 2017, and the IE filed the Report of the Independent Evaluator on the draft RFP as required by Task A7 of the IE Scope of Work on August 11, 2017.
In its report on the proposed solicitation process, the IE identified additional issues of concern and also identified positive aspects of the draft RFP. A list of conclusions and recommendations from the IE Report on the Draft RFP are listed below.

Conclusions

- The RFP documents and process are generally consistent with the Utah Admin. Code, Regulations and Statutes pertaining to the requirements for the design and development of the competitive bidding process. The IE believes that PacifiCorp has adequately addressed most of the requirements listed in the Statutes. However, under the current structure of the RFP it is not certain if the solicitation process will lead to the acquisition and delivery of electricity at the lowest reasonable cost to the retail customers. The IE and others have suggested revisions to the RFP which should hopefully result in a more competitive process that will verify the IRP action plan identified by PacifiCorp without extending the solicitation process schedule, which could jeopardize the potential benefits to customers;

[7] PacifiCorp provided the RFP Base model to the IEs on July 27, 2017 for review. PacifiCorp noted the model did not include the update assumptions and inputs but the model structure would generally be the same as provided.

- The integration of the wind generation resources in conjunction with a new 140-mile 500 kV transmission line from the Aeolus substation to the Bridger/Anticline substation (Aeolus to Bridger/Anticline transmission line) could pose risks to bidders and consumers if the transmission project is not built on time to allow bidders or benchmark resources to achieve Production Tax Credit ("PTC") benefits;

- The 2017R RFP is a reasonably transparent RFP, with a significant amount of information provided to bidders on which the bidders could base their proposals;

- The 2017R RFP is designed to provide the same information to all bidders including the benchmark options;

- The products sought in this RFP are clearly defined and the information required for each type of resource alternative is specified in the RFP in a clear and concise manner;

- The RFP documents clearly describe the products requested, the requirements of bidders, the evaluation and selection process, and the risk profile of the buyer. In this regard, there is sufficient information to allow bidders to assess whether or not to compete, the product of choice to bid to be most competitive, and the process by which their proposals will be evaluated;

- There are a number of safeguards included in the solicitation process which should ensure that all bidders will have access to the same information at the same time with no undue benefit for the benchmark bids;

- Parties have raised the issue of ensuring comparability for resource evaluation, notably ensuring that utility benchmarks and third-party PPA and Build Transfer bids are required to compete based on the same set of rules or on a level playing field. The IE also views comparability to be the most challenging issue in a solicitation process in which utility-owned resources compete with third-party resources. The nature of these resources is very different to begin with. Third-party PPA options submit a price schedule that is firm at the time of submission. Changes in the cost of equipment or market prices can affect the final economics either positively or negatively, with the bidder absorbing the risk of higher project costs or enjoying the benefits or lower project costs. Utility-owned options, on the other hand are submitted as reasonable estimates. If costs increase, the utility could request the ability to pass through the costs to customers assuming the costs are deemed to be prudently incurred. Cost decreases, on the other hand, are passed through to customers. Given the different risk profiles, contract terms, etc. it is extremely difficult to create a fully level playing field on which both types of resources can compete. Merrimack Energy has proposed several ways to create a more level playing field in the solicitation process.

- The evaluation process and quantitative methodologies developed by PacifiCorp for undertaking the initial price screening evaluation (spreadsheet model formerly referred to as RFP Base Model) and for selecting the final short list (System Optimizer and PaR models) are applicable for the modeling of the proposals expected in this RFP. Furthermore, the model methodology is consistent with and likely exceeds industry standards applied by others for conducting such a price and risk analysis. While the spreadsheet model may be unique to PacifiCorp, the model methodology and concept is consistent with the approaches applied by others, notably a comparison of the costs and benefits for each proposal. The portfolio evaluation and risk assessment methodologies are very detailed and are generally pertinent to the requirements of the Energy Procurement Resource Act.

- The evaluation and selection process appears to be a comprehensive process designed to evaluate the cost implications associated with different resource portfolios, the important non-price factors required in the Act that influence project viability, and assesses the risk parameters associated with the portfolios.

- PacifiCorp met the requirements of Utah Admin. Code R746-420-1(2) and the Scheduling Order in Docket No. 17-035-23 by providing the IE with data, information and models necessary for the IE to analyze and verify the models. PacifiCorp provided the IE with the latest version of its price screening spreadsheet model that will be used for the phase 1 shortlist evaluation as well as the latest input assumptions, which may be subject to revisions.

Recommendations

- Both Merrimack Energy and UAE have raised issues with regard to comparability associated with the risk issues allocated to each resource type (i.e. PPA, BTA, and benchmark) and comparability associated with the resources evaluation process (contract term/evaluation horizon). Merrimack Energy has undertaken a detailed assessment of the Power Purchase Agreement ("PPA") and Build Transfer Agreements ("BTA") and identified the risks in each contract. Merrimack Energy concluded that there are very different risk provisions in the PPA and BTA agreements which could unduly favor the Benchmark options. PPA and BTA bidders were allocated significant risk which could either eliminate potential bid options or lead to much higher prices for these options if the bidder prices the risk into its bid price. We suggested that PacifiCorp either revise the contracts to create a more balanced risk profile or allow bidders to provide comments on contract issues with their proposals. For example, in response to a question from Merrimack Energy regarding contract risk allocation, PacifiCorp stated that the contracts will be subject to negotiations, apparently meaning that PacifiCorp is willing to recognize that bidders may take exception with certain provisions of the contracts. The IE has suggested that bidders be allowed to either red-line the PPA or provide comments on the Agreements with their proposals to assess if there are 'deal breaker" provisions in the contracts that will affect all or a significant portion of the bidders. PacifiCorp could then decide to make revisions to the contracts in conjunction with input from the IEs to ensure the contract provisions do not unduly bias a resource selection decision;

- The IE has also provided recommendations associated with meeting the requirements in the statute for equivalent contract terms. Section R746-420-3(8)(k) states that the solicitation must allow power purchase contract terms equivalent to the projected facility life of the Benchmark option, which we understand to be 30 years. The recommendation of the IE is to allow PPA bidders to offer either a 30-year term or a 20-year contract with up to a 10-year extension that is a firm price and would be exercised at the option of the buyer;

- Merrimack Energy has also recommended that the eligibility provisions in the RFP be expanded. This includes removing the requirement that only new wind projects who can quality for the full PTC benefits are eligible. Instead, the IE supports PacifiCorp's recent decision to lift the full PTC requirement and allow other bidders that may also have unique competitive advantages to compete. The IE also recommended that existing projects that are not under contract at the time of bid submission and who proposed repowering their wind projects were also eligible to bid. Finally, the IE agreed with the Division of Public Utilities regarding the proposal to allow broader access to PacifiCorp's load center by eliminating the requirement in the Draft RFP that the bidder must use the proposed Aeolus to Bridger/Anticline ("Gateway Segment D2" or "D2") transmission facilities or demonstrate they can deliver the power into Wyoming. This would allow PacifiCorp to determine if its action plan for 1,270 MW of wind generation combined with construction of the transmission facilities associated with Aeolus to Bridger/Anticline transmission line would be economic and provide value to customers;

- Merrimack Energy recommended that the Commission grant PacifiCorp's request for a waiver of the bid binding requirements in the Statute (Utah Admin. Code R746-420-3(10)(a). However, the IE still suggested that questions and answers would be blinded in that PacifiCorp would not know the identity of the bidder when the questions from the bidder was provided to them by the IE. Merrimack Energy would remove the name or reference to the bidder prior to submitting the question to PacifiCorp for a response;

- The IE recommended that PacifiCorp allow bidders to submit a base bid and two alternatives for the bid fee of $10,000 instead of the base bid and one alternative, particularly since PacifiCorp was encouraging PPA bidders to include a purchase option proposal with their bid. If bidders offer a purchase option presumably this would serve to use up their one allowable alternative;

- Given the importance of transmission, the IE suggested that PacifiCorp consider either providing a workshop on transmission and interconnection requirements and status of options or include a detailed discussion of these issues as part of the Bidders Conference to be held on September 12, 2017;

- The IE suggested that PacifiCorp consider revising its non-price factors to include project viability characteristics for the projects. In the view of the IE, some of the factors identified by PacifiCorp were really eligibility or threshold criteria (i.e. bids provide all required RFP information) and not non-price factors. The IE identified factors such as experience of the bidder, access to generating equipment, financing plan, O&M plan, etc. as criteria or factors to consider;

- There is little information regarding credit requirements to allow bidders to reflect the credit requirements in their bids or affect their decision to compete, unlike previous PacifiCorp RFPs. PacifiCorp could either include credit requirements based on $/kW bid or update its previous credit methodology;

- The IE recognized the potential issues associated with new lease accounting rules and Variable Interest Entity (VIE) treatment, particularly since PacifiCorp had stated in the RFP that it would not be subject to projects that trigger VIE treatment, for example. Merrimack Energy included suggested language in this section of the RFP to require PacifiCorp to provide documentation to the IE justifying any decision to reject a bid due to accounting issues;

- Task B3 of the IE Scope of Work as listed in the Commission's RFP for Independent Evaluator required the IE to set up and maintain a webpage or database for information exchange between bidders/potential bidders and PacifiCorp **only if directed by the PSC in its Approval of the Solicitation Process.** Merrimack Energy proposed to establish a webpage on its website to accommodate this requirement similar to the webpages we established for previous PacifiCorp RFPs. The webpage would be used to accept questions from bidders, which Merrimack Energy staff will blind by removing the name of the bidder, before sending the questions to PacifiCorp for a response. Merrimack Energy would then review the responses and post the Question and Answer to the webpage for bidders to review. Merrimack Energy would also post any RFP documents on the webpage as well as posting any Notices to bidders of upcoming schedule items or changes to RFP documents.

As a result of the comments of parties and the report submitted by the IE, PacifiCorp agreed in its Reply Comments on August 18, 2017 to make several revisions to the RFP prior to the Commission hearings on the RFP, including the following:

- Expanded the eligibility provisions to allow both new wind projects and repowered existing wind resources to submit proposals, as long as the repowered project does not have an existing PPA with PacifiCorp;
- Revised the non-price factors to include project viability characteristics, such as experience of the bidder, access to generating equipment, financing plan, O&M plan, etc.;

- Included credit requirements for bidders in the RFP to allow bidders to reflect the credit requirements in their bids;
- Provided equivalent contract terms for PPA bidders, allowing PPA bidders to offer either a 30-year term or a 20-year contract with up to a 10-year extension that is a firm price and would be exercised at the option of the buyer;
- Company proposed to require Bidders to provide a System Impact Study by the date of the initial shortlist rather than at the time of proposal submission;
- PacifiCorp objected to the request of the Division and IE to eliminate the requirement that the bidder must use the proposed Aeolus to Bridger/Anticline transmission facilities or demonstrate they can deliver into Wyoming.

On August 22, 2017, the Commission issued its Order and Notice of Scheduling Conference. The Commission concluded that it had an insufficient record to make a finding of fact. The Commission also concluded that additional time to analyze the RFP is warranted and in the public interest.

Hearings on the Company's application took place on September 19, 2017. At the hearing, PacifiCorp agreed to broaden the scope of the RFP to wind resources that could deliver output from anywhere on PacifiCorp's transmission system. Therefore, an eligible bid would now include all wind facilities located in the PacifiCorp system outside of Wyoming with the proven ability to directly interconnect with the PacifiCorp transmission system, or deliver energy to PacifiCorp through the use of third-party firm transmission service.

The Commission issued its Order on September 22, 2017 approving the RFP with suggested modifications. The Order:

1. Approved the RFP as proposed by PacifiCorp, including modifications proffered during the hearings to be accepted by PacifiCorp;
2. Suggested a modification to the RFP that PacifiCorp expand the RFP to include solar resources that can interconnect at any point in PacifiCorp's system. Whether or not PacifiCorp accepts this suggested modification, the Commission did not require any additional approval prior to RFP issuance;
3. Approved PacifiCorp's request for a waiver of Utah Admin. Code R746-420-3(10)(a) requiring the IE to blind all bids for the evaluation process;
4. Directed the IE to set up and maintain a webpage or database for information exchange between bidders, potential bidders, and PacifiCorp.

The RFP was issued on September 27, 2017.

Table 1 lists the key provisions in the 2017R Renewable RFP included in Docket No.17-035-23 on the Commission website.

Table 1
Summary of Key Provisions of the Draft 2017R RFP

RFP Characteristics	All Source RFP
Resource Requirements	PacifiCorp is seeking cost-effective bid for up to 1,270 MW of wind energy resources interconnecting with or delivering to PacifiCorp's Wyoming system and any additional wind energy located outside of Wyoming that will reduce system costs and provide net benefits for customers. Bidders should assume that Wyoming projects can interconnect to, or deliver via third-party transmission to the proposed 500-kV Energy Gateway segment D2 Aeolus-to-Bridger/Anticline substation and transmission system. Proposals for wind resources claiming PTC eligibility must demonstrate to PacifiCorp's satisfaction that projects will qualify for the federal PTC, if applicable.
Resource Timing – On-line Date	PacifiCorp will only consider projects that demonstrate a unique value opportunity for its customers and achieve commercial operation by December 31, 2020, without compromising system reliability.
Eligibility	PacifiCorp will accept proposals for new or repowered existing wind resources capable of directly interconnecting and delivering energy to PacifiCorp's network transmission system in PACW and PACE or capable of delivering energy to PacifiCorp's transmission system in PACW and PACE with the use of third-party transmission service. Minimum project size is 10 MW Bids submitted with repowered wind resources will only be allowed for an existing wind resource that currently: • Does not have a power purchase agreement with PacifiCorp for the offtake of the energy, or • Has an active power purchase agreement with PacifiCorp that naturally expires before December 31, 2020. • Failure to demonstrate a commercial operation date prior to December 31, 2020. Failure to provide two years of wind resource data for a proposed wind project submitted as a BTA and one year of wind resource data if the wind project is proposed as a PPA
Resource Alternatives/Transaction Structures	PacifiCorp will consider proposals for the following transaction structures: (1) Build-Transfer transaction whereby the bidder develops the project, assumes responsibility for construction and ultimately transfers the operating asset to

	PacifiCorp upon or prior to December 31,2020; and. (2) Power Purchase Agreement for up to a 30-year term with exclusive ownership by PacifiCorp of any and all environmental attributes associated with all energy generated. At the Bidders option, the PPA bid submittal can include two distinct alternatives: • A proposed contract term ranging between 20 and 30 years, with or without the right for PacifiCorp to purchase the project assets during or at the end of the proposed contract term at fair market value (FMV) to retain the value of the site for customers, or • A 20-year PPA term with an option for PacifiCorp to extend the PPA term at a proposed fixed price ($/MWh) for up to 10 years. PacifiCorp also announced plans to offer at least 860 MW of new wind projects as self-build options. The benchmark resources would be completed via an Engineering, Procurement, and Construction ("EPC") contract.
Bid Alternatives	For each bid proposal, bidders must submit a bid fee of $10,000, which allows a bidder to submit a base proposal and two alternatives for the same $10,000 bid. Bidders will also be allowed to offer up to three additional alternatives at a fee of $3,000 each. Alternatives will be limited to different bid sizes, contract terms, in-service dates, and/or pricing structures.
Bidding Process	The Company will conduct a multi-stage process. In the first stage, the bidder must submit both the "Intent to Bid Form" and the Bidder's Credit Information Appendices B and D). In the second stage, bidders are required to submit their proposals and respond to the requirements for the type of resource alternative they are proposing. All bidders must submit Appendix C – Bid Summary and Pricing Input Sheet. Bids that make the short list will be allowed to provide a Best and Final Offer. Best and Final Prices must be within 10% of the Bidders original total bid cost relative to the cost of the bid selected in the initial short list.
Utility Bid Options	The Company proposes to submit four individual wind Benchmark Resources to satisfy approximately 860 MW of targeted wind resources. A description of the projects is included in Appendix L.
Evaluation Process – Short List Selection	PacifiCorp proposes a two-phase price evaluation process, with multiple steps as will be described in more detail below. The two phases include (1) an Indicative Bid stage as the basis for selecting a short list and (2) Best and Final Offer.

	In the first phase, PacifiCorp will establish an initial shortlist based on both price and non-price factors, The Company intends to evaluate each bid received in a consistent manner by separately evaluating the non-price characteristics of the resource and the price characteristics. Price will account for 80% of the score and non-price for 20% (or a maximum of 20 points). From a pricing perspective, all bids will be evaluated using PacifiCorp's proprietary spreadsheet model to calculate the delivered revenue requirement cost of each benchmark resource and market bid, inclusive of any applicable carry cost and net of production tax credit benefits. The delivered revenue requirement cost will be netted against energy, capacity, and terminal value benefits, as applicable, to calculate the net cost of each benchmark resource and market bid. The net cost calculation will be used to assign a price score to each benchmark resource and each market bid. This will be achieved by calculating the nominal levelized (discounted) revenue requirement cost and the nominal levelized (discounted) benefit for each benchmark resource and market bid, where revenue requirement costs are reported as a negative value and customer benefits are reported as a positive value. The calculated net benefit for each benchmark resource and market bid will be forced ranked based for the $/MWh price category with an upper boundary of 80 points. Forced ranked bids grant the maximum of 80 points to evaluated bids with the highest calculated net benefit and the lowest evaluated bid get 0 points. PacifiCorp will use the combined price and non-price results to rank benchmark resources and market bids. Based on these rankings, PacifiCorp will select an initial shortlist based on total bid score (maximum at 100%, with a maximum of 80% for price and a maximum of 20% for non-price factors). Bid that make the short list will be allowed to provide a Best and Final Offer. Best and Final pricing shall not exceed 10% of the original total bid cost, which PacifiCorp will assess on a present value revenue requirements basis. In the event that best and final pricing increases the total benchmark resource or market bid cost by more than 10%, PacifiCorp reserves the right to either (a) reject the best and final proposal or, (b) replace the shortlisted bid or bid alternative with a final proposal solicited from another bid not originally selected to the initial shortlist.
Non-Price Evaluation	In phase 1 of the evaluation process, price and non-price

	weights are combined to select the short list within each resource Category. The non-price characteristics include: (1) Conformity to RFP Requirements; (2) Project Deliverability; and (3) Transmission Progression.
Phase 2 – Final Shortlist	PacifiCorp will use the System Optimizer (SO) model to develop a resource portfolio containing the 2017R RFP bids with the Aeolus to Bridger/Anticline transmission project. For purposes of the 2017R RFP, the SO model will be used to select the combination of wind projects from the initial shortlist, up to approximately 1,270 MW, that minimizes system costs among a range of different environmental policy and market price scenarios. The SO model will also be used to establish least cost resource portfolios for each policy-price scenario without any new wind and without the Aeolus to Bridger/Anticline transmission project. For each policy-price scenario, PacifiCorp will calculate the present value revenue requirement differential (PVRR(d)) between the portfolio containing 2017R RFP wind resources with the Aeolus-to-Bridger/Anticline project, including all transmission costs, and the portfolio without 2017R RFP wind resources and without incremental transmission costs. PacifiCorp will also evaluate each of the resource portfolios developed with the SO model using Planning and Risk (PaR). For purposes of the 2017R RFP, PaR will be used to calculate the stochastic mean PVRR(d) and the risk-adjusted PVRR(d) for each policy-price scenario. Based on the results of the evaluation and in consultation with the IEs, PacifiCorp will select one or more 2017R RFP wind resource portfolios for further scenario risk analysis. Before establishing a final shortlist, PacifiCorp may take into consideration, in consultation with the IEs, other factors that are not expressly or adequately factored into the evaluation process described above, particularly any factor required by applicable law or Commission order.
Credit Requirements	PacifiCorp will evaluate credit requirements for shortlisted bidders. Credit requirements for bidders are described in Appendix D of the RFP.
Transmission	PacifiCorp is seeking resources capable of (1) directly interconnecting with PacifiCorp's system in its PACW and PACE balancing areas or (2) interconnecting with a third-party system and using third-party firm transmission service to deliver to PacifiCorp's transmission system. With either method, PacifiCorp prefers bids that will not face significant transmission costs or constraints between the resource and

	PacifiCorp network load. While PacifiCorp provides these general guidelines, the available transfer capability from the project or project delivery points to PacifiCorp's network load cannot be known or estimated until the bidder identifies its proposed point of interconnection/point of delivery.
Accounting Issues	All contracts proposed to be entered into as a result of this RFP will be assessed by PacifiCorp for appropriate accounting and tax treatment. Given the term length of the PPA, or the useful life of the asset to be acquired under an asset acquisition or alternative ownership proposal, accounting and tax rules may require either: (i) a contract be accounted for by PacifiCorp as a capital lease or operating lease pursuant to ASC 840, or (ii) the seller or asset owned by the seller, as a result of an applicable contract, be consolidated as a variable interest entity (VIE) onto PacifiCorp's balance sheet. PacifiCorp is unwilling to be subject to accounting or tax treatment that results from VIE treatment. As a result, after bidders are selected for the shortlist, if required by PacifiCorp accounting department, bidders will be required to certify, with supporting information sufficient to enable PacifiCorp to independently verify such certification, that their proposals will not be subject to VIE treatment.
Imputed Debt	PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt as part of the economic analysis in the shortlist evaluation. However, after completing the shortlist and before the final resource selections are made, PacifiCorp may take direct or inferred debt into consideration. In so doing, PacifiCorp may obtain a written advisory opinion from a rating agency to substantiate PacifiCorp's analysis and final decision regarding direct or inferred debt.
Code of Conduct	A Code of Conduct is included in the RFP as Appendix N.
Benchmark Bids	Appendix L of the RFP provides a summary of PacifiCorp's Company Alternatives (Benchmark Resources).
Role of the IE	Appendix M to the RFP describes the role of the IE in the process.
Contracts	The Company provides a sample PPA and Build-Transfer Agreement (BTA).
Schedule	A detailed schedule was provided in the RFP including the following important dates: • RFP Issued to Market – September 27, 2017 • Bidders Conference – October 2, 2017 • Notice of Intent to Bid – October 9, 2017 • Benchmark Bids Due – October 10, 2017 • Wyoming Bids Due – October 17, 2017

	• Non-Wyoming Bids Due – October 24, 2017 • Initial Shortlist Evaluation/Scoring Completed – November 12, 2017 • IE Review of Initial Shortlist Completed – November 17, 2017 • Best and Final Price Update – November 22, 2017 • Final Shortlist Evaluation Completed – January 8, 2018 • IE review of Final Shortlist Completed – January 15, 2018 • Execute Agreements – April 16, 2018

In addition to the RFP document, PacifiCorp provided a number of Appendices to the RFP with its filing. The Appendices to the RFP are listed below.

1. RFP Main Document
2. Appendix A – 2017R Renewable Project Technical Specification
3. Appendix B – Notice of Intent to Bid and Information Required in Bid Proposals
4. Appendix C – Bid Summary and Pricing Input Sheet (Instructions for PPA and BTA)
5. Appendix D – Bidder's Credit Information
6. Appendix E-1 – PPA Instructions to Bidders
7. Appendix E-2 – Power Purchase Agreement (PPA) Documents
8. Appendix F-1 – BTA Instructions to Bidders
9. Appendix F-2 – Build Transfer Agreement (BTA) Documents
10. Appendix G – Confidentiality Agreement and Non-Reliance Letter
11. Appendix H – Reserved
12. Appendix I – FERC's Standards of Conduct
13. Appendix J – Qualified Reporting Entity Services Agreement
14. Appendix K – General Services Contract - Operations and Maintenance Services for Project
15. Appendix L – PacifiCorp's Company Alternative (Benchmark Resource)
16. Appendix M – Role of the Independent Evaluator
17. Appendix N – Code of Conduct Governing PacifiCorp's Intra-Company Relationships for RFP Process
18. Appendix O – Description of PacifiCorp's Proposed Gateway Segment D Transmission Project

Bidders Conference

The Bidder's Conference/Workshop was held on October 2, 2017 at two locations: Salt Lake City and Portland. In addition, participants could call in to the webinar. The key agenda items addressed at the Bidder's Conference included the following:

- RFP Key Points
- RFP Schedule
- Bid Proposal Types and Structures

- Benchmark Resources
- Interconnection and Transmission Service
- Credit and Credit Requirements
- Bid Submission Requirements
- Minimum Eligibility Requirements
- Instructions for PPA and BTA Submissions
- Bid Evaluation Process and Shortlist Selection
- Independent Evaluators
- Communication
- Next Steps
- Questions and Comments

There were 125 participants present at the Bidder's Conference/Workshop including 11 in person at the Salt Lake City site, 15 in Portland and 99 via the Webinar. A copy of the attendees is provided on the PacifiCorp website for this RFP.

Questions and Answers

Consistent with the Commission's Order, Merrimack Energy set up a separate webpage for the PacifiCorp 2017R RFP on its website. Bidders who wished to remain anonymous could submit questions to the Merrimack Energy webpage for the PacifiCorp RFP and Merrimack Energy would blind the Bidder's name prior to sending the question to PacifiCorp for a response. In addition, Bidders could also submit questions directly to PacifiCorp. The IE and PacifiCorp collaborated on exchanging the questions and responses to ensure there was consistency regarding the Q&As posted to each website. PacifiCorp's website contained 12 Q&As associated with the Bidder's Conference/Workshop, and 23 Q&As submitted after the Bidder's Conference. Merrimack Energy's webpage included 26 Q&As, including some Q&As that were posted to both websites.

Input Assumptions

An important part of any bid evaluation process is the development of the input assumptions that will be used as the basis for consistently evaluating proposals received. Ideally, a utility will prepare its input assumptions, share the assumptions with the IE, and lock-down the assumptions prior to submission of proposals. PacifiCorp sent its input assumptions for the 2017R RFP to the IEs on October 6, 2017 (Task B1), prior to receipt of proposals. PacifiCorp and the IEs participated in a call to discuss any questions of the IEs on October 9, 2017. In preparation for the call, Merrimack Energy sent several questions to PacifiCorp regarding the input assumptions. The input assumptions file submitted by PacifiCorp included the flowing Tabs:

- Financial Tab
  - Inflation rates – from 2017 IRP
  - AFUDC rate
  - Capital Structure – from 2017 IRP
  - Asset Lives

    - Property tax rates
    - Bonus Depreciation
    - ITC for Wind
    - PTC for Wind[8]
  - Owners Costs (for utility-owned wind projects)
    - Owners costs
    - O&M costs
    - Insurance
    - Decommissioning
  - Wind Integration Costs – From 2017 IRP
  - Third-party Transmission Costs
  - System Benefits Curves
    - Combined energy and capacity system benefit by major location
    - Monthly price curves (high and low load hours) for Mona (Wyoming); Mona (UT/ID); Mid-C (OR/WA).

PacifiCorp proposed Operation and Maintenance and Administrative and General Costs ("OMAG") to be [redacted]kW for Tier 1 wind turbines escalated by inflation after year 3. PacifiCorp included an Insurance cost of [redacted] per $100 of capital. PacifiCorp also provided a backup cost table which verified the costs used for the evaluation based on PacifiCorp's experience operating wind turbine projects.

For integration costs, PacifiCorp provided its estimate based on its 2017 Flexible Reserve Study from the 2017 IRP. The latest study results include wind integration costs of $.57/MWh in $2017 compared to $3.06/MWh from the 2014 Wind Integration study. The latest cost estimate is comprised of $.43/MWh for Intra-hour Reserves and $.14/MWh for inter-hour/System Balancing.

PacifiCorp's input assumptions also include Monthly ACC (Alternative Cost of Compliance) values for Wyoming (Mona), UT/ID (Mona) and OR/WA (Mid-C) regions. The ACC uses system costs and benefits from an IRP model run as a replacement for market and leaves out a Renewable Energy Certificate ("REC") assumption.

The IEs and PacifiCorp held a conference call on October 9, 2017 to discuss the assumptions and any issues associated with any values or the methodology for generating the forecast. Merrimack Energy asked questions relating to the basis for developing the forward price curves for electricity, financial inputs, and the basis of the O&M cost estimates and their relationship to the O&M costs for the benchmark. Merrimack Energy was particularly concerned about the OMAG assumptions which appeared to be low relative to the IEs experience and low relative to the inputs used by PacifiCorp in its 2017 IRP.

Merrimack Energy reviewed the input assumptions provided by PacifiCorp and had several follow-up questions relating to the following cost items:

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[8] Section 2 of this report provides a description of the basis for the PTC assumptions used in the evaluation.

1. Basis of the AFUDC rates;

2. Owners Costs including the basis and reasonableness of OMAG costs, inclusion of Capital expenditures, and the relationship between the OMAG costs included in the assumptions tab compared to the O&M costs included in the IRP;[9]

3. System Benefits Curves, including questions on the factors that explain the much lower monthly ACC forecast for Mona for the UT/ID area as opposed to Wyoming;

4. The basis for the integration cost assumptions for wind presented in the input assumptions backup based on the Flexible Reserve Study as described in the IRP relative to the higher values used in the 2014 IRP.

A copy of the input assumptions file submitted by PacifiCorp to the IEs is included as Appendix A to the IE Shortlist Report.

<u>Notices of Intent to Bid</u>

As described in the 2017R RFP document, bidders who intended to participate in the RFP must submit an Intent to Bid Form and Credit information to PacifiCorp and the IEs as an initial non-binding step in the process. Bidders were required to provide this information by October 9, 2017. Table 2 provides a high-level summary of the Notices of Intent to Bid results. Appendix B to the IE Shortlist Report contains the summary of the Notices of Intent by bidder as compiled by PacifiCorp.

Table 2: Summary of Notices of Intent to Bid Responses

Region	Number of Potential Bidders	Project Options	Total Potential Capacity (MW)
Wyoming	12	36	9,559
Non-Wyoming	8	10	1,652
Total	20	46	11,211

[9] PacifiCorp provided a comparative response regarding the basis for the O&M costs contained in the input assumptions file and the O&M costs included in the IRP.

IV. Bid Evaluation Methodology

A. Summary of PacifiCorp's Evaluation and Selection Process

Section 6 of the 2017R RFP provides a description of the bid evaluation process and methodology for the 2017R RFP. According to the RFP "PacifiCorp's bid evaluation and selection process is designed to identify the combination and amount of new or repowered wind projects bid into the 2017R RFP that will maximize customer benefits. The method used to evaluate and select bids is consistent with the methods that were used to evaluate new or repowered wind resources and transmission infrastructure in PacifiCorp's 2017 IRP." The same method will be used to evaluate benchmark resources and market bids.

PacifiCorp indicated that it intended to utilize a two-phase evaluation process. The two phases include (1) an initial bid stage as the basis for selecting a shortlist and (2) Best and Final Offer process. In the first phase, PacifiCorp would establish an initial short-list based on both price and non-price factors. Updated pricing was not permitted during this phase. After the initial short-list was established, all bids (and alternatives) for the selected bid would be given the opportunity to provide best and final pricing.[10] In the second phase, the updated pricing for short-listed bids would be analyzed with the same production cost models used to develop PacifiCorp's 2017 IRP preferred portfolio. These production cost models would be used to perform a net customer benefit analysis by simulating PacifiCorp's system costs with and without initial shortlist bids. PacifiCorp's production cost modeling would be used to calculate the expected net present value revenue requirement impacts, accounting for risk.

B. Shortlist Evaluation Methodology

According to the RFP, PacifiCorp will use the combined price and non-price results to rank benchmark resources and market bids. Based on these rankings, PacifiCorp would select the initial short list based on price and non-price factors, with price weighted up to 80% and non-price up to 20%. The RFP stated that PacifiCorp would seek to establish an initial shortlist of up to approximately 2,000 MW of aggregate wind capacity for Wyoming projects that are reliant on the Aeolus-to-Bridger/Anticline transmission project and up to 2,000 MW for projects not dependent on the Aeolus-to-Bridger/Anticline. However, PacifiCorp, in consultation with the IEs, may establish an initial shortlist containing less or more aggregate capacity depending upon the relative total bid score among benchmark resources and market bids.

From a pricing perspective, all proposals would be evaluated using PacifiCorp's proprietary spreadsheet model to calculate the delivered revenue requirement cost and benefit of each benchmark resource and market bid, inclusive of any applicable carrying costs and net of production tax credit benefits and other benefits. The delivered revenue

[10] As noted, PacifiCorp's evaluation process included a best and final pricing option. However, due to the passage of the Federal Tax Bill and the possible impacts on corporate tax rates and the value of the PTC benefits, PacifiCorp offered bidders the opportunity to update pricing in late December, 2017.

requirement cost would be netted against energy, capacity, and terminal value benefits, as applicable, to calculate the net cost of each benchmark resource and market bid. The net cost calculation would be used to assign a price score to each benchmark resource and each market bid. This would be achieved by calculating the nominal levelized (discounted) revenue requirement cost and the nominal levelized (discounted) benefit for each benchmark resource and market bid, where revenue requirement costs are reported as a negative value and customer benefits are reported as a positive value.

The nominal levelized net benefit reflects interconnection network upgrade costs, but does not include the cost of the Aeolus-to-Bridger/Anticline transmission line, which would be captured in the economic analysis informing selection of the final shortlist. As stated in the RFP, PacifiCorp would use cost data for each benchmark resource and market bid. The assumptions made for financial inputs and PacifiCorp carrying costs would be applied consistently to benchmark and market offers. For Build-Own-Transfer options in which PacifiCorp would eventually own the project, project costs include operating costs required of PacifiCorp as well as capital related costs associated with rate base treatment for the project under cost of service regulations. PacifiCorp also considered the value of the Production Tax Credit (“PTC”)[11] or Investment Tax Credit (“ITC”) as a benefit to the BTA option for the bid evaluation process. PPA bidders would incorporate the benefit of PTCs in their PPA pricing proposal.

The nominal levelized revenue requirement cost (negative value) and benefit (positive value) for each bid will be used to calculate the net cost in order to rank the bids. According to the RFP document, the calculated nominal levelized $/MWh net benefit for each benchmark resource and market bid will be forced ranked, with a maximum of 80 points to the evaluated bid with the highest calculated net benefit, a minimum of zero points to the evaluated bid with the lowest calculated net benefit, and the remaining bids scored on a 0 to 80-point scale according to the relationship of their respective calculated net benefits to those of the highest and lowest bids. PacifiCorp stated it would also rank the bids per the IE-recommended ranking methodology used in PacifiCorp’s previous RFPs for purposes of comparison as part of the initial shortlist evaluation.[12] If the methodologies result in different initial shortlists, PacifiCorp indicated it would include in its initial shortlist all bids supported by both methodologies.

As noted above, for the initial price evaluation, PacifiCorp would run its traditional RFP Base spreadsheet model to calculate both the costs and benefits associated with each proposal. The cost/benefit components and values vary depending on whether a bid is a

[11] In its application for issuance of the RFP, PacifiCorp stated that the target date for the 2017R RFP was driven by the need to capture a time-limited resource opportunity arising from the expiration of the federal production tax credits (“PTCs”). The Company indicated it would procure the proposed wind resources in conjunction with a new 140-mile, 500 kV transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to a new annex substation, Bridger/Anticline, located near the existing Jim Bridger substation. The project must achieve commercial operation by the end of 2020 to qualify for the full value of the PTCs.

[12] PacifiCorp used these two methodologies as well as a third methodology for allocating price and non-price points. These methodologies will be discussed in greater detail later in this report in the section pertaining to actual shortlist evaluation and selection.

PPA or BTA. Table 3 provides a summary of the cost and benefit components for each option to set the stage for review of the summary results for each proposal. A value in parentheses (i.e. (X)) reflects a cost component while Z reflects a benefits component for purposes of assessing the net benefits of each option.

Table 3: Summary of Cost/Benefit Components for Each Bid Type

Component	PPA Option	BTA Option
PPA Bid Price ($/MWh)	(X)	
Capital Revenue Requirements	-	(X)
PTC Benefit	-	***Z***
Integration Cost	(X)	(X)
O&M, Lease, Insurance	-	(X)
Property Taxes	-	(X)
Wyoming Wind Tax	-	(X)
Network Upgrade Revenue Requirements	(X)	(X)
Terminal Value	-	***Z***
Energy and Capacity Value	***Z***	***Z***

The components included in the cost of energy category vary by bid type. For PPA options, the cost of energy is based on the fixed price or base price and fixed escalation rate submitted by the bidder on its Pricing Input Sheets (Appendix C) times the expected energy generated by the proposal.[13] For BTA options, PacifiCorp calculates Capital Revenue Requirements over the life of the asset. The total in-service capital cost of the project will be the primary starting point for this cost component. This will include the capital cost of the project, interconnection and network upgrade costs, owner's costs and development costs, contingency, AFUDC and capitalized property taxes. PacifiCorp will include the capital cost of the project in rate base and amortize the costs over 30 years based on utility revenue requirements principles.

In developing revenue requirements costs, PacifiCorp will use cost data for each benchmark and market bid. Any internal assumptions for key financial inputs (i.e. inflation, discount rates, marginal tax rates, asset lives, AFUDC rates, etc.) and PacifiCorp carrying costs (i.e. integration costs, owner's costs, etc.) would be applied consistently to benchmark resources and market bids, as applicable. The cost of the Aeolus-Bridger/Anticline transmission project would not be directly assigned to specific benchmark resources or market bids during the initial shortlist price evaluation.

The value of the Production Tax Credit (PTC) applies only to BTA options since the PPA bidder incorporates the value of the PTC in its own project cost proposal. PacifiCorp assumes a PTC value of $24/MWh in 2017 dollars which is assumed to escalate annually

[13] For this stage of the evaluation, PacifiCorp generally accepts (subject to discussions with bidders or clarification questions) the generation profile and capacity factor as given and does not conduct due diligence on the generation profile or capacity factor at this stage of the process.

at 2%. PacifiCorp indicated it prefers projects that can meet the requirements to provide the full value of the PTCs for the benefit of customers.[14]

Integration costs are applied to all proposals. Wind integration costs included in the evaluation are equal to $.57/MWh based on PacifiCorp's 2017 Flexible Reserve Study ("FRS") as included in the 2017 IRP. Integration costs include $.43/MWh for Intra-hour reserve and $.14/MWh for Inter-hour/System Balancing.

Operation and Maintenance Costs and Admin and General (OMAG) costs are included for BTA and benchmark options. The basis for these costs include the O&M costs proposed by the equipment supplier for the first 3 years of operations followed by estimates prepared by PacifiCorp based on its own experience owning and operating wind projects. The proposed OMAG costs estimated by PacifiCorp was provided to the IEs as an input assumption. Merrimack Energy questioned the estimate as being on the low side based on other solicitations. PPA bidders include OMAG costs in their bid price.

Network upgrade revenue requirements are included for all proposals. All bids would be evaluated individually for the initial shortlist evaluation based on the direct assigned interconnection costs and any third-party transmission upgrade costs associated with the specific interconnection, if so relied upon for delivery to a specified point of delivery, that were submitted in the bids. All proposals will require firm transmission to PacifiCorp's network transmission system.

Terminal value benefits are included for benchmark and BTA options. In the RFP, PacifiCorp noted that one of the components of project value is terminal value. Generally, terminal value for a generation facility at the end of its useful life is equal to its net salvage value. However, the other assets associated with a wind site, such as land, site characteristics and generation interconnection and transmission facilities may have value beyond the assumed useful life of wind energy facilities. [redacted] Under this approach, the terminal value reflects the depreciated value of assets that have not fully depreciated at the end of the assumed 30-year life for the wind facility (i.e. transmission assets associated with a wind facility) and the appreciated value of other elements of the project that remains at the end of the assumed 30-year life for the wind facility (i.e. development rights and land, as applicable).

Energy and capacity benefits are included for all proposals submitted. Energy and Capacity Value will be based on two production cost model runs for prospective bids delivering output to varying locations on PacifiCorp's system. For each location (Wyoming, Utah, Idaho, and Washington/Oregon), one simulation would include proxy wind resources and new transmission, as applicable, at a zero cost and one simulation would exclude proxy wind resources and new transmission, as applicable. The

[14] Under the IRS Safe Harbor requiring continuity of construction, generally the wind facility must be placed in service no later than the end of the fourth calendar year following the year that construction work started, i.e. if construction was started in December of 2016, the facility would need to be placed in service by December 31, 2020 to qualify for the 100% PTC.

differential in system fixed and variable costs between the two production cost model simulations would serve as the basis for the expected energy and capacity benefits associated with new or repowered wind facilities at varying locations.

As previously noted, PacifiCorp provided the model output results of the evaluation for all the bids submitted to the IEs. Merrimack Energy's project team reviewed the results and prepared a summary of the bids based on the comparison metrics for the price component of the evaluation. The model runs also included comparative costs in $/MWh. In addition, PacifiCorp also conducted a non-price evaluation of the bids received.

The primary purpose of the non-price assessment was to help gauge other factors that may influence project viability. PacifiCorp developed 3 different non-price categories for a total of 20% for non-price. The three non-price categories were: (1) conformity to RFP requirements with 4% weight; (2) project deliverability for 8%; (3) transmission progression for 8%. [15] The percentages in each category were divided into 3 specific percentage weights: (1) 100%; (3) 50%; and (5) 0%. Thus, if a bid received a score of 50% for conformity to RFP requirements, the score for that category would be 2%. The non-price scores will not be force ranked. Each bid will have its price score added to the non-price score. The bidders with the highest total score (price and non-price), and representing up to approximately 2,000 MW of aggregate capacity at any given location, would be considered for the initial shortlist.

C. Final Shortlist Evaluation Methodology

Proposals that make the short list would be allowed to provide a Best and Final Offer. Best and final pricing must be provided for the same site using the same or similar technologies as originally proposed. Best and Final pricing shall not exceed 10% of the original total bid cost, which PacifiCorp would assess on a present value revenue requirements basis. In the event that best and final pricing increases the total benchmark resource or market bid cost by more than 10%, PacifiCorp reserves the right to either (a) reject the best and final proposal or, (b) replace the shortlisted bid or bid alternative with a final proposal solicited from another bid not originally selected to the initial shortlist.

To determine the final short list, PacifiCorp utilized the same cost model used for the initial short list price evaluation, with bids updated for best and final pricing and projected performance, to process bid costs for input into IRP production cost models. In processing benchmark resource and market bid costs, PacifiCorp stated that it would convert the calculated revenue requirement associated with capital costs (i.e. return on investment, return of investment, and taxes, net of PTCs, as applicable) to first year real levelized costs, consistent with the treatment of capital revenue requirements in PacifiCorp's IRP modeling. All other benchmark resource and market bid costs would be summarized in nominal dollars and formatted for input into the IRP models, consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling.

[15] The non-price criteria involved a combination of objective assessment (i.e. bidder provides the information requested) and subjective assessment designed to assess the viability or quality of the project.

Projected resource performance data (expected hourly capacity factor information) would also be processed for input into the IRP models.

PacifiCorp utilized the System Optimizer ("SO") model, which was used to develop resource portfolios in the 2017 IRP, to develop a resource portfolio containing the 2017R RFP bids with the Aeolus-to-Bridger/Anticline transmission project.[16] For purposes of the RFP, the SO model would be used to select the combination of wind projects from the initial shortlist. For Wyoming wind that requires construction of the Aeolus-to-Bridger/Anticline transmission project for interconnection, the model would be able to select up to approximately 1,270MW of new or repowered wind capacity.[17] The model would also identify resource portfolios containing projects that are not dependent on the Aeolus-to-Bridger/Anticline transmission project. For bids that are not dependent upon the Aeolus-to-Bridger/Anticline transmission project for interconnection, the model would be able to select new or repowered wind capacity at any level that reduces system costs, thereby demonstrating net benefits for customers. In addition, the model would establish the least cost resource portfolio without any new wind and without the transmission project. For each scenario, PacifiCorp would calculate the present value revenue requirement (PVRR) to determine the best-case scenarios that have the highest benefit for customers.

Once the portfolios are calculated in the SO model, PacifiCorp then uses the Planning and Risk (PaR) model to perform stochastic risk analysis of the portfolios produced by SO. PaR uses the same common input assumptions described for the SO model. Once unique resource portfolios are developed using the SO model, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed in PaR.

For each SO portfolio, PaR studies are developed for three natural gas price scenarios (base, high, and low) and two carbon dioxide (CO2) emissions limit assumptions. The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio.[18] While PaR cost-risk metrics are ultimately used in

[16] The System Optimizer model produces unique resource portfolios across a range of different planning assumptions. The SO model calculates the system present value revenue requirement (PVRR) by identifying least cost resource portfolios and dispatching system resources over a 20-year forecast period. The SO model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon (2017-2036 for this RFP), it optimizes resource additions subject to resource costs and capacity constraints. To accomplish these optimization objectives, SO performs a time-of-day least-cost dispatch for existing and planned generation, while considering cost and performance of existing contracts and new demand side management alternatives within PacifiCorp's transmission system.

[17] PacifiCorp informed the IEs that there is a 240 MW QF project in the interconnection queue that will absorb a portion of the transmission capacity on the Aeolus-Bridger/Anticline line, leaving approximately 1,030 MW for RFP proposals on this system.

[18] Resource portfolios developed with SO are simulated in PaR to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using Monte-Carlo sampling of stochastic variables across the

the preferred portfolio selection, SO model results remain valuable and informative, especially in their role as a magnitude and direction indicator to compare to PaR outcomes.

V. Bid Submission and Bid Evaluation Process

This section of the report describes the evaluation and selection process from receipt of proposals through final selection of the revised final shortlist. This phase of the solicitation process occurred from early October, 2017 through mid-February, 2018, taking approximately one month longer than the schedule included in the RFP. PacifiCorp began conducting its evaluation of the proposals shortly after proposals were received. Proposal submissions dates were staggered in order to conduct evaluations in a fair and appropriate manner and provide reasonable time to adequately submit and evaluate bids in three categories: PacifiCorp's benchmark bids, Wyoming bids, and non-Wyoming bids. As a result, PacifiCorp's Benchmark Bids were due October 10, 2017 while the Wyoming bids and Non-Wyoming bids were due on October 17, 2017 and October 24, 2017, respectively. The evaluations of the Benchmark Bids were completed prior to the receipt and evaluation of the market bids.

During the months of October, 2017 through mid-February 2018, PacifiCorp provided the IEs with presentations containing the evaluation results for shortlist selection, model runs for each proposal, summaries of the results of the best and final pricing, and updated pricing to reflect the bidder's incorporation of the Federal Tax Bill ("Tax Cuts and Job Act") in their final pricing. In addition, the IEs and PacifiCorp held discussions regarding potential updates to input assumptions and proposed changes made by PacifiCorp to the generation profiles of Bidders due to the report prepared by its consultant, Sapere Consulting, based on the consultant's review of the generation estimates provided by each shortlisted project. The documents provided by PacifiCorp to the IEs served as the basis for review and discussions and as supporting information for the selection of the final shortlist. PacifiCorp presented the results to the IEs at each phase of the evaluation process (i.e. Phase 1 – Initial Shortlist and Phase 2 – Final Shortlist). Conference calls were held with the parties to discuss the results and address any questions. The evaluation results presented by PacifiCorp and reviewed and verified by the IEs will be discussed in this Report.

Each of the major activities and milestones associated with the receipt, evaluation and selection of the final proposals are described and discussed in this section of the report.

A. Benchmark Resources

Another requirement for the IE (Task B4) was to review and validate the assumptions and cost calculations of any benchmark resource options and analyze the benchmark option(s) for reasonableness and consistency with the solicitation process prior to submission of

20-year study horizon, which includes load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages.

third-party bids.[19] To undertake this task the IEs held conference calls with PacifiCorp's Benchmark team to review and assess the benchmark resources. PacifiCorp provided copies of the 4 benchmark proposals (Ekola Wind, TB Flats I and II; TB Flats I; and McFadden Ridge Wind) to the IEs on or around October 11, 2017 (Task B4). Merrimack Energy reviewed the benchmark proposals submitted, prepared a list of follow-up questions and submitted the questions to PacifiCorp, and prepared a summary of the proposals for inclusion into Merrimack Energy's report on the Benchmark resources as required by the IE Scope of Work.

According to Appendix L of the RFP, PacifiCorp intended to submit four individual wind benchmark resources to satisfy approximately 860 MW of targeted wind resources. The benchmarks would be new greenfield wind resources that would be constructed in Wyoming on property either currently leased by PacifiCorp or that PacifiCorp has acquired rights to develop.[20]

All projects had a proposed in-service date of 2020 and would qualify for the full Production Tax Credit. PacifiCorp indicated in its proposal that it intends to hold a separate competitive solicitation to secure firm fixed pricing for an Engineering, Procurement and Construction ("EPC") agreement to construct the project. PacifiCorp indicated that the benchmark resources would include 30-year pro-forma estimates for operations, maintenance and on-going capital expenditures. Benchmark resource costs would also include allocated development costs, fees, permitting, project management and safe harbor equipment costs.

Based on discussions with PacifiCorp, the benchmark cost estimates were based on a number of factors. These include: actual cost for turbines acquired, EPC and Balance of Plant ("BOP") costs based on the average of the three lowest bids submitted by the five EPC contractors contacted to provide estimates, experience from operations and development for other wind projects owned by PacifiCorp, and inputs from the IRP input files.

Table 4 presents overall summary information for each Benchmark resource as provided in the benchmark proposal. Table 5 provides a breakdown of the capital cost components by category as provided by PacifiCorp in a presentation provided to the IEs on October 16, 2017. This information was also included in the project cost spreadsheets included in PacifiCorp's benchmark proposals as submitted to the IEs.

[19] PacifiCorp was required to evaluate and score the benchmark resources consistent with the shortlist evaluation methodology to be applied to all proposals. The IE was required to validate the evaluation results prior to evaluation of third-party proposals.
[20] PacifiCorp entered into a Development Transfer Agreement with Invenergy Wind Global LLC for three projects from Invenergy (TB Flats I and II, TB Flats I, and Ekola Flats). Through its Development Transfer Agreement, PacifiCorp secured long-term exclusive leasehold rights to develop and construct the majority of the sites required. Invenergy also had the rights to submit these proposals into the PacifiCorp 2017R RFP.

Table 4: Summary Information for the Benchmark Options

Benchmark Options Summary Information	**TB Flats 1 and TB Flats 2**	**Ekola Flats**	**McFadden Ridge**	**TB Flats 1**
Summary Info				
Project Name	TB Flats 1 and TB Flats 2	Ekola Flats	McFadden Ridge	TB Flats 1
Size (MW)	501.2	249.8	109.2	250.6
Location	12 miles northeast of Medicine Bow in Carbon and Albany counties, Wyoming	7 miles northwest of Medicine Bow in Carbon County, Wyoming	7.6 miles northeast of Arlington in Carbon and Albany County Wyoming	16 miles north of Medicine Bow in Carbon County, Wyoming
In-Service Date	11/1/2020	11/1/2020	11/1/2020	11/1/2020
Interconnection Point	Shirley Basin Substation	Aeolus Substation	Foote Creek substation	Shirley Basin substation
Annual Generation (GWh) (P50)	[redacted]	[redacted]	[redacted]	[redacted]
Net Capacity Factor (%)	[redacted]	[redacted]	[redacted]	[redacted]
Interconnection Agreement	No	No	No	No
Studies Completed	System Impact Restudy	System Impact Study	None	System Impact Study
Direct Assigned Transmission costs	[redacted]	[redacted]	[redacted]	[redacted]
Network Upgrade Costs	[redacted]	[redacted]	[redacted]	[redacted]
Pricing Information				
Capital Cost[21]	[redacted]	[redacted]	[redacted]	[redacted]
Installed Cost/kW	[redacted]	[redacted]	[redacted]	[redacted]
O&M Cost – Year 1	[redacted]	[redacted]	[redacted]	[redacted]
O&M Cost – Year 4	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor Amount	[redacted]	[redacted]	[redacted]	[redacted]
Percent Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]

[21]Capital costs include Wind Project costs, Direct Assigned Interconnection costs, Owners and Development costs and Contingency as described in Table 4. Interconnection Network Upgrade costs, AFUDC, and Capitalized Property Taxes are not included in Capital costs.

Table 5 Capital Cost Components for Each Benchmark Resource

Cost Components	TB Flats 1 and TB Flats 2	Ekola Flats	McFadden Ridge	TB Flats 1
Capital Costs (million $)				
Wind Project	[redacted]	[redacted]	[redacted]	[redacted]
Interconnection (direct Assigned)	[redacted]	[redacted]	[redacted]	[redacted]
Interconnection (Network Upgrades)	[redacted]	[redacted]	[redacted]	[redacted]
Owner's and Development Cost[22]	[redacted]	[redacted]	[redacted]	[redacted]
Contingency	[redacted]	[redacted]	[redacted]	[redacted]
AFUDC	[redacted]	[redacted]	[redacted]	[redacted]
Capitalized Property Tax	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Cost	[redacted]	[redacted]	[redacted]	[redacted]
Cost - $/kW	[redacted]	[redacted]	[redacted]	[redacted]

One of the focuses of this report was an assessment of the reasonableness of the costs of the benchmark resources. For this report, the IE relied upon generic cost information to assess the reasonableness of the capital and O&M costs of the benchmark resources. The IE concluded that the capital costs of the benchmarks (with the exception of the McFadden Ridge project) appeared to be [redacted] than market indicators based on the studies reviewed and analyzed by Merrimack Energy. As a result, the IE felt that the capital costs of the benchmarks should be scrutinized during the evaluation process to ensure that the costs were reasonable with regard to actual bids and would not be subject to cost uncertainty and possible requests for increases in costs if the project(s) are selected for the final shortlist.

Consistent with the requirements of the IE for assessing the benchmark resource as identified in Utah Rule R746-420 Requests for Approval of a Solicitation Process, Merrimack Energy reviewed the detailed information submitted by PacifiCorp and prepared a report on the benchmarks. In preparation of the report, Merrimack Energy reviewed the information provided by PacifiCorp, submitted a list of questions to PacifiCorp, and participated in a lengthy conference call with PacifiCorp and the Oregon IEs to review the benchmarks and the responses to the IE questions.

22 [redacted]

Merrimack Energy assessed and evaluated the benchmark resource relative to the following factors:

1. The level of detail presented for the benchmark resource to support the cost and operating parameters for the benchmark;

2. Whether PacifiCorp included all cost elements in their project cost;

3. Reasonableness of the capital costs for the benchmark option;

4. Reasonableness of the fixed and variable operations and maintenance cost projections;

5. Reasonableness of the proposed availability for the unit;

6. Generation profiles and reasonableness of the level of generation and the net capacity factor for each proposal;

7. Capital additions;

8. Completeness of the information presented relative to the requirements for information from other bidders.

With regard to the first two factors, Merrimack Energy completed a review and assessment of the detailed cost data supporting the cost information included in the benchmark resource proposal. As presented in its benchmark proposals, PacifiCorp stated that the capital cost cash flows associated with development, property, equipment, construction, startup, and commissioning of the project are provided in a detailed worksheet in its proposals which identify a wide range of cost components. The capital costs presented include the owner-supplied equipment (wind turbine generators), Engineering, Procurement and Construction ("EPC") Balance of Plant Construction, project contingency, development fees (success fee to Invenergy), owner provided builders risk insurance, direct assigned transmission interconnection costs, working capital (critical spare parts), project management, permitting, capitalized environmental mitigation costs, startup and commissioning, training and other owner's costs.

Our assessment of the information provided by PacifiCorp in its benchmark proposals indicate that PacifiCorp has compiled a significant level of information on which to base its costs in this RFP process. The information on capital cost and annual operating cost was well organized and clearly labeled in the spreadsheets provided to the IE's. The level of information is thorough and reviewable and represents credible and detailed sources of information. Based on our review, it is obvious PacifiCorp has undertaken a detailed assessment of the capital and operating costs of the benchmark resources at this stage in the process. Furthermore, we have not identified any major cost category that was not included in the detailed backup information or that will be included in the evaluation by PacifiCorp's Evaluation Team.

One of the general concerns in auditing the benchmark capital costs is to ensure that the estimated capital cost is reasonable and within industry cost bounds for the technology proposed. As a result, Merrimack Energy was focused on ensuring that the Company did not offer an unrealistically low estimate relative to market benchmarks or competitive options.

A comparison of the capital cost of the benchmark resources relative to the market benchmark capital costs from recent studies illustrates that three of four benchmark proposals have [redacted] on a $/kW basis than the cost levels illustrated by the studies. Only the McFadden Ridge project (109 MW) has a similar capital cost to those presented in the market benchmark studies. The McFadden Ridge project is the smallest of the project proposed by PacifiCorp. This may explain the relative economics with other smaller, 100 MW projects identified in the studies and furthermore, may support the reasonableness of the costs for larger wind projects submitted by PacifiCorp having a [redacted] than the study benchmarks. Nevertheless, three of the projects proposed by PacifiCorp have [redacted] on a $/kW basis than the market price benchmark, which may merit oversight during the evaluation process as more data becomes available from the actual proposals submitted.

The same trend is true for O&M costs. All the benchmark studies reviewed estimate O&M costs of over [redacted]. Merrimack Energy has estimated O&M costs for wind turbines to be about [redacted], in previous wind benchmark cost studies. Three of the four benchmark projects have O&M costs that are below $30/kW when comparing the O&M costs beginning in year 4 of the contract term. Only McFadden seems to fit the market price benchmark estimates. The other three projects are all lower cost from an O&M perspective in addition to a capital cost perspective. PacifiCorp may be able to take advantage of its portfolio of wind projects and its strategy of retaining an O&M contractor for all its projects based on economies of scale. The cost information provided by three of the four benchmark proposals are lower than the market price benchmarks in terms of capital and O&M costs. These lower costs could be attributed to economies of scale. PacifiCorp has indicated that most of the costs are fixed which would lead us to believe that PacifiCorp would be willing to stand by these cost estimates.

For wind projects, an important consideration for calculating costs and benefits is the level of generation expected from this project. This is particularly important for wind projects where a large percentage of the costs of the project are fixed costs. High capacity factor wind projects, for example, could have a higher overall cost but a lower unit cost if the level of generation is higher than a competitor. PacifiCorp intends to have a third-party firm review the generation profiles of the bidders to ensure their generation profiles are not unreasonable given their location and past history of the area with regard to wind speeds.

In addition to presenting its capital and operating costs for each benchmark, PacifiCorp's Evaluation Team was also required to evaluate and score the benchmark resources and lock-down the scores prior to the evaluation of other proposals. The IE was required to audit and verify the evaluation results. Table 6 provides the results of the evaluation and analysis prepared by PacifiCorp and scrutinized and validated by the IE. In this case, PacifiCorp presented the IEs with their spreadsheet model results for each project and convened a conference call to take questions and comments from the IEs. In addition, PacifiCorp provided the non-price evaluation results based on the non-price criteria specified in the RFP. After review of the model results, the IE did not find any inconsistencies or errors in the analysis.

Table 6: PacifiCorp Price Evaluation Results for the Benchmark Resources Nominal Levelized Benefits and Costs $/MWh[23]

Category	Ekola Flats	TB Flats 1 and 2	McFadden Ridge	TB Flats 1
Wind Capital Revenue Requirements	[redacted]	[redacted]	[redacted]	[redacted]
Transmission Capital Revenue Requirements	[redacted]	[redacted]	[redacted]	[redacted]
PTC Benefit	[redacted]	[redacted]	[redacted]	[redacted]
O&M, Lease, Insurance	[redacted]	[redacted]	[redacted]	[redacted]
Property Taxes	[redacted]	[redacted]	[redacted]	[redacted]
WY Wind Tax[24]	[redacted]	[redacted]	[redacted]	[redacted]
Integration	[redacted]	[redacted]	[redacted]	[redacted]
Delivered Cost	[redacted]	[redacted]	[redacted]	[redacted]
Energy & Capacity Value	[redacted]	[redacted]	[redacted]	[redacted]
Terminal Value	[redacted]	[redacted]	[redacted]	[redacted]
Total Value	[redacted]	[redacted]	[redacted]	[redacted]
Net Benefit/(Cost)	[redacted]	[redacted]	[redacted]	[redacted]

The results of the pricing analysis illustrate that all of the benchmark resources have a significant positive value for customers (i.e. positive net benefits value). This is marked by delivered cost in the [redacted] range and reasonably high capacity and energy value. As a utility-owned project, PacifiCorp is also including terminal value in its calculations to reflect the value remaining for assets such as interconnection facilities, access roads and infrastructure, and other assets that have value going forward after the useful life of the wind generation asset. While terminal value is relatively low, in a competitive solicitation it could contribute to influencing proposal ranking since terminal value is only applied to utility ownership options.

[23] Merrimack Energy has revised the presentation of results relative to PacifiCorp's approach. For example, the above table includes benefits as positive values and costs as negative values ($).
[24] The Wyoming generation tax is $1.00/MWh. Since the tax goes into effect on 11/1/2023, the projects affected are operable for nearly two years before the tax goes into effect, resulting in a lower levelized cost of $.80/MWh.

As noted, PacifiCorp also evaluated the benchmark options from a qualitative perspective based on the non-price evaluation criteria included in the 2017R RFP. Table 7 presents a summary of the results of the non-price evaluation, including the final scores for each benchmark resource.

Table 7: Non-Price Evaluation Results

Project	Conformity to RFP Requirements (4% possible)	Project Deliverability (8% possible)	Transmission Progression (8% possible)	Total Non-Price Score (20% Possible)
Ekola Flats	[redacted]	[redacted]	[redacted]	[redacted]
TB Flats I & II	[redacted]	[redacted]	[redacted]	[redacted]
TB Flats I	[redacted]	[redacted]	[redacted]	[redacted]
McFadden Ridge II	[redacted]	[redacted]	[redacted]	[redacted]

Based on Merrimack Energy's review of the benchmark proposals submitted, discussions with the Benchmark Team, and review and assessment of the supporting information, Merrimack Energy reached the following conclusions with regard to the reasonableness of the benchmark options as described in the IE report:

1. PacifiCorp developed detailed cost information about the benchmark resources and provided their proposals along with the background information and spreadsheets detailing the cost by line item to the IEs for review and assessment of the benchmark resources. The information presented in its submittals, notably Appendix C Input Pricing and Data Sheets is consistent with overall solicitation requirements for all proposals and is thorough in describing the benchmark

proposals. Furthermore, in our view all relevant cost information appears to be included in the cost of the benchmark options;

2. The capital cost estimates provided PacifiCorp for three of the four benchmark resources appear to be [redacted] information included in the benchmark market studies reviewed. The capital cost of the smallest project, the McFadden Ridge II project, a 109 MW wind project, is similar in cost to the 100 MW options commonly applied in the market benchmark studies. The capital costs for the other three PacifiCorp benchmark resources may reflect economies of scale associated with larger projects. Overall, we feel that the capital costs are reasonable for the benchmark resources but if there is any deviation from the average we feel it would be on the [redacted] of the cost spectrum;

3. We also conclude that the O&M costs presented by PacifiCorp are reasonable, but like capital costs, may be a bit [redacted] relative to competitive options;

4. The benchmark proposals contain all the information required of other bidders and will be evaluated consistent with the methodology used to evaluate all bids submitted. The level and detail of information provided by PacifiCorp was very thorough and exceeds industry standards for benchmark resources at this stage in the process. The evaluation results described in the IE report were generated using the same methodology and assumptions as PacifiCorp intended to use to evaluate third-party BTA and PPA options;

5. In our view, PacifiCorp has conformed to the requirements of Rule R746-420 based on the amount of information provided, the level of detail provided for this information, and the methodology for calculating the cost and value of the benchmark proposals;

6. In conformance to the requirements of Utah Rule R746-420, the IE can confirm that we did assess and validate the benchmark options. The IE expects that there will be no changes to any aspects of the benchmark evaluation results after validation by the IE. The IE can confirm that the benchmark option will not be subject to any changes unless updates to other bids are permitted;

7. The IE confirms that all relevant costs and characteristics of the benchmark resource were audited and validated by the IE. The final evaluation results and scores of each benchmark resource should be reasonable and consistent;

8. The review, assessment and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward perception of bias.

B. Proposals Submitted

Proposals were submitted on three different dates, with the Benchmarks submitted first, followed by the Wyoming proposals a week later, and the non-Wyoming proposals one week after the Wyoming proposals were submitted. PacifiCorp received a total of 72 bids, including all alternatives, which included 4 Benchmark bids, 49 bids from independent power producers for Wyoming projects and 19 bids from independent producers for non-Wyoming projects.[25] By type of proposals, 4 were benchmarks, 50 were PPA options, and 15 were BTA options. There were also proposals that included a combined PPA/BTA proposal. One bidder offered the opportunity to purchase the development rights for specific projects. A summary of the proposals submitted is included in Table 8. Appendix C to the IE Shortlist report contains a full summary of the all the proposals and options submitted, with detailed information about each proposal, including proposal pricing.

Table 8: Summary of Proposals Submitted

	Number of Bidders[26]	Bids Submitted
Benchmarks	1	4
Wyoming		
PPA	8	35
BTA	5	11
PPA/BTA	1	1
Purchase Development Rights	1	2
Non-Wyoming		
PPA	6	15
BTA	2	4
Total		72

The participants in the RFP included many of the largest wind developers in the country, who are active in many power markets in the US and elsewhere. Table 9 provides a list of the project developers who submitted proposals, along with the number of specific projects proposed and proposal options submitted. Since most developers submitted multiple proposals that varied by proposal size or pricing structure, we have listed the sizes also submitted.

Table 9: Summary of Proposals Submitted By Bidder

Bidder Name	Project Name	Number	Number of	Sizes (MW)

[25] Merrimack Energy's totals for proposals submitted include all proposals and options submitted, including those that were eliminated as non-conforming.
[26] Several bidders included both PPAs and BTAs. Bidders who propose both PPAs and BTAs are included in both categories for consistency sake.

		of PPA Options	BTA options	
Wyoming Wind Proposals				
[redacted]	[redacted]			[redacted]
[redacted]	[redacted]			[redacted]
[redacted]	[redacted]			[redacted]
[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]		[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]

The amount of MWs submitted (based on the largest project by MW) submitted exceeded the amount PacifiCorp indicated it was seeking in the solicitation by a factor of over [redacted] times, illustrating a very robust response from the market to the RFP.

Based on the initial review of the proposals received, a number of bidders still had outstanding data gaps that prevented PacifiCorp from initiating the evaluation. This required the Company to communicate with a number of bidders, including the Benchmark team, to clarify information presented in the proposals prior to undertaking the initial price and non-price assessment. During this phase of the process several bids were initially classified as non-conforming. The primary reasons for non-conformance included the following:

[redacted]

[redacted]
The IEs were both in agreement with PacifiCorp's decision to classify the above proposals as non-conforming.

C. Evaluation of Wyoming and Non-Wyoming Proposals

PacifiCorp provided the economic models with the evaluation results for each Wyoming proposal to the IEs on or around November 9, 2017 followed by the non-Wyoming proposals shortly thereafter. Merrimack Energy reviewed and scrutinized the models in detail for a number of the proposals, including [redacted] to ensure the evaluation results were reasonable and consistent.

Merrimack Energy's team members participated on calls with the PacifiCorp evaluation team shortly after receipt of the model results and outputs for each proposal and posed several clarifying questions as a result of reviewing the model evaluation results prior to shortlist selection, including questioning whether BTA offers had an inherent competitive advantage over PPAs based on the evaluation methodology. These questions included:

1. Why do [redacted] generally have significantly more AFUDC included than [redacted] projects? Is it attributed to the progress payment schedule or some other factors?
2. Why do the BTA options for [redacted] have a higher Energy and Capacity value than the PPAs for the same projects? The values are quite a bit different. The same is true for other cases where a bidder offers both a BTA and PPA for the same project (i.e. [redacted]). Is it related to the longer term for the BTA?
3. Are all the projects located in Wyoming delivering to the same pricing point for evaluation purposes? There appears to be some differences for different proposals.

PacifiCorp provided reasonable responses to all outstanding questions raised by the IEs.[27]

[27] With regard to the first question above PacifiCorp noted that the timing for incurring capital cost for the Invenergy proposal was earlier in the development cycle and at a higher level than for the benchmark option, which would result in higher AFUDC values for the Invenergy proposal. PacifiCorp also stated that the term of the proposals (30-year BTA vs 20-year PPA) result in higher capacity and energy values for the longer-term option based on forecasts of these values. In response to the third question, PacifiCorp noted that the differences in value for each proposal delivering to the same pricing point would be attributed to the generation profile of each proposal based on the timing of output.

Merrimack Energy also prepared a summary of the results by benefit and cost component for the top ranked projects for each proposal and conducted further review in cases where the results appeared inconsistent. Table 10 provides evaluation results for each proposal based on the best option for each proposal. Appendix D to the IE Shortlist report provides a summary of each eligible proposal and option submitted by cost and component as well as identifying the capacity factor and equipment proposed for each proposal.

Table 10: Evaluation Results – Wyoming and Non-Wyoming Proposals

Bidder Name	Project Name	Size (MW)	PPA or BTA	Levelized Net Benefit ($/MWh)[28]	Non-Price Scores
Wyoming Proposals					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Wyoming Proposals					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

D. Initial Shortlist Selection

PacifiCorp also submitted slide deck presentations to the IEs for the Wyoming and non-Wyoming proposals separately, which included a detailed summary of the evaluation results for each proposal in early November. PacifiCorp and the IEs held a conference call to review and discuss the proposed shortlist as presented in PacifiCorp's slide decks.

PacifiCorp noted that the nominal levelized net benefits calculated reflect interconnection network upgrade costs but did not include the cost of the Aeolus-Bridger/Anticline transmission line, which would be included in the economic analysis informing selection of the final shortlist. The presentation included a preliminary viability assessment for the top ranked projects as well as summary information on each of the proposals submitted. Appendix E to the IE Shortlist report is the slide deck for the Wyoming proposals while Appendix F is the slide deck for the non-Wyoming proposals.

[28] Positive value means that benefits exceed costs.

Table 10 includes the projects proposed by PacifiCorp for inclusion on the initial shortlist based on the projects identified in its slide deck. Table 11 contains the summary evaluation results of the price and non-price scores for each eligible proposal. The proposals are organized by shortlist location (WY and non-WY). In total there are nine WY projects selected for the initial shortlist for a total of [redacted] of cumulative capacity. There were an additional three projects selected to the initial shortlist for non-WY projects totaling [redacted] of cumulative capacity.

Based on the results of the evaluation, PacifiCorp, the Oregon IE and the Utah IE discussed the selection of the initial short list and agreed upon the selected resources. PacifiCorp recommended selection of shortlisted bids significantly above the level of capacity proposed in the RFP. For example, the RFP stated that PacifiCorp would seek to establish an initial shortlist of up to approximately 2,000 MW of aggregate wind capacity for Wyoming projects that are reliant on the Aeolus-to-Bridger/Anticline transmission project and up to 2,000 MW for projects not dependent on the Aeolus-to-Bridger/Anticline transmission project. PacifiCorp recommended nearly [redacted]. In addition, in its slide deck presentation, PacifiCorp did not include its [redacted] The Oregon IE inquired whether PacifiCorp would include its benchmark resource for [redacted] on the shortlist and PacifiCorp indicated the project was on the shortlist based on its ranking as the 6th highest ranked project but was not listed because the [redacted] was ranked higher for shortlist evaluation.

Table 11: Proposed Initial Short List

Bidder Name	Project Name	Size (MW)	PPA or BTA	Cumulative Capacity (MW)	Price Score[29]	Non-Price Scores	Total Score
Wyoming Proposals							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[29] PacifiCorp calculated the price score using three scoring methodologies: (1) scores were scaled so that the lowest net cost (NC) minus benefit (NB) (or highest net benefit) was awarded the full 80 points and a breakeven proposal was awarded 0 points; (2) Scores were scaled such that the highest net cost – benefit (or highest net benefit) was awarded 80 points and the lowest was awarded 0 points, with scores pro-rated in between; and (3) Scores were scaled so that the highest ranked net cost minus benefit (highest net benefit) was awarded 80 points and lowest ranking proposal was awarded 0 points with points for the remaining projects pro-rated. For the first methodology Bidder Score (Bidder x) = 1-([NC/(B)lowest – NC/(B) (Bidder x)]/NC/(B) lowest) x 80. For the second methodology Bidder Score (Bidder x) = [(NC)/B (Bidder x) – (NC)/B lowest)/((NC)/B highest – (NC)/B lowest] x 80. For the third methodology Bidder Score (Bidder x) = (80 points – ((Rank of (NC)/B (bidder x -1) x (80 points/ Number of Ranked Bidders - 1)))).

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Wyoming Proposals								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For the Wyoming proposals, PacifiCorp's rationale for selecting such a robust shortlist was that the proposals were all ranked closely with no defined break points until the drop off in benefits beginning with the [redacted]. The IE recognized the competitiveness of the highest ranked proposals and attempted to identify other potential break points but after discussion of other options the IE agreed with the shortlist selection by PacifiCorp. PacifiCorp's shortlist selection was designed to be project specific. In other words, a project was selected to the shortlist and bidders still had the option of providing a best and final offer for any of the options submitted by the bidder for that project. The IEs also agreed with this approach because it may lead to an overall more efficient selection for portfolio development since there is a possibility that a smaller project size from one bidder could be a better option than another larger project with a lower value (i.e. net benefit).

PacifiCorp notified the shortlisted bidders of their selection to the shortlist on November 17, 2017. PacifiCorp informed bidders of the date for submitting best and final offers. Also, PacifiCorp informed the bidders that one of the requirements of shortlist selection was that each bidder was required to provide an acceptable Commitment Letter within 20 business days after the bidder was notified that the bidder was selected for the shortlist.[30]

Several shortlisted bidders took exception to the Commitment Letter requirement (i.e. submit 20 days after shortlist notification) identified by PacifiCorp in its notification letter to shortlisted bidders. Merrimack Energy recognized this issue as a similar issue that emerged in the 2012 PacifiCorp RFP nearly ten years ago. Merrimack Energy contacted PacifiCorp and also took exception to this requirement. Merrimack Energy and PacifiCorp reviewed prior RFP documents, including IE reports, and realized that PacifiCorp had agreed in the 2012 RFP, at Merrimack Energy's recommendation, to move the due date for the Commitment Letter to 20 days after final selection, not shortlist selection.[31] The IE and PacifiCorp agreed with the revision in this requirement.

[30] The Credit Requirements listed in Appendix D of the RFP states "If necessary, the bidder will be required to demonstrate the ability to post any required credit assurances in the form of a commitment letter from a proposed guarantor or from a financial institution that would be issuing a Letter of Credit. PacifiCorp will require each bidder to provide an acceptable commitment letter(s), if applicable, twenty (20) business days after the bidder is notified that the bidder has been selected for the Shortlist. Bidder will be required to provide any necessary guaranty commitment letter from the entity(ies) providing guaranty credit assurances on behalf of the bidder and/or any necessary letter of credit commitment letter from the financial institution providing credit assurances in the form of a Letter of Credit.

[31] One of the issues raised by bidders in the 2012 RFP was that Credit Support Providers would be required to identify this commitment or obligation on its financial statements even though there was no guarantee of a contract award at this stage. Credit Support Providers appeared amendable to providing a commitment

PacifiCorp informed bidders of the revision to the schedule. There were no further comments from bidders.

E. Best and Final Pricing

As described in the RFP, all initial shortlisted bidders were requested to offer best and final pricing for their shortlisted projects. Bidders were notified of their shortlist selection on November 17, 2017 and were required to submit best and final pricing by November 22, 2017. As outlined in the RFP, best and final pricing must be based on the same site with the same or similar technology as the original proposal. In addition, best and final pricing cannot exceed 10% of the original bid cost. Many of the shortlisted bidders decided to offer a best and final price, with some proposing increases and others decreases. [redacted] was generally the most aggressive of the bidders, proposing fairly significant reductions in the [redacted] Table 12 presents a comparison between the initial pricing contained in the original proposal and the best and final pricing submitted on November 22, 2017. As Table 12 demonstrates, [redacted] proposals and also experienced the largest reduction for the best and final pricing, further expanding the differential in capital cost with other comparable options. For example, [redacted]

Table 12: Best and Final Pricing

Bidder	Project	Bid Type	Capacity (MW)	First Year Price ($/MWh)	Annual Escalation (%)	Capital Cost ($/kW)	Best and Final Price[32]
Wyoming Proposals							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]

letter later in the selection process (i.e. final shortlist selection) if the project was selected for contract negotiations.

[32] This column provides any updated base prices proposed by each bidder. In all cases, the rate of escalation is the same as in column 6 in Table 11.

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]							
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]

The best and final pricing results illustrate several different directions regarding pricing changes. [redacted] In addition, in its best and final offer [redacted] agreement approved by the Commission. PacifiCorp indicated it suggested this option because parties in the Company's ongoing EV2020 regulatory approval dockets have indicated a reluctance to support Company acquisition of additional wind resources on the basis that cost and performance risks may exceed customer benefit. To address this concern, [redacted].
As noted above, the alternative structure relative to the Company's currently submitted benchmarks would incorporate an unregulated affiliate of the Company which would develop and own the project and deliver energy to the Company pursuant to a PPA. [redacted] The PPA would include an option to purchase the asset at the end of the term at fair market value. PacifiCorp stated that this alternative structure and approval of the project would be subject to and conditioned upon approval of the power purchase agreement by relevant state and federal regulatory agencies.[redacted]

<u>F. Independent Consultant Analysis of Shortlisted Bids Generation Profile</u>

PacifiCorp utilized a third-party consultant, Sapere Consulting, to verify the wind capacity factors for each shortlisted project based on generation data provided by each of the shortlisted bidders for the projects included on the shortlist. At Merrimack Energy's request, PacifiCorp provided a copy of the contract with Sapere to understand their scope of work. According to PacifiCorp's schedule, the report was supposed to be available by end of November; however, the IE was not provided a copy of the report until mid-December after requesting a copy of the report. The conclusions reached by Sapere for each shortlisted project are as follows:

- [redacted] "There is a likelihood that the project will not perform as proposed."
- [redacted] "There is a likelihood that the project will not perform as proposed."
- [redacted] "This project is likely to perform as proposed unless the [redacted] is constructed on the adjacent property as proposed.
  This has the potential to significantly impact the wind output at [redacted]
- [redacted] "This project is likely to perform as proposed."

2. [redacted])
   - "There are material omissions and inconsistencies relating to the wind resource assessment compared to industry practice… Consultant suggests obtaining a full wind resource analysis with financing-level detail, to confirm what looks like an otherwise attractive wind resource, before accepting this project."
   - [redacted] "There are material omissions and inconsistencies relating to the wind resource assessment compared to industry practice… Given the uncertainties and limitations of the wind resource analysis proposed, it is Sapere's opinion that the [redacted] has a material likelihood to not perform as proposed."
   - [redacted] "This Project is likely to perform as proposed, but further diligence relating to the possibility of wake effects from the proposed McFadden II project is prudent."
   - [redacted] "This project is likely to perform as proposed."
   - [redacted] "This project has a likelihood of not performing as proposed. Further due diligence relating to wind resource analysis and assumptions is prudent prior to accepting this project."

- [redacted] "Based on results from an admittedly "preliminary" wind resource assessment, this project is likely to perform as proposed, but further diligence, including securing a final or "financing level" wind resource study would be prudent prior to accepting this project."

- [redacted] "There is a likelihood that this project will not perform as proposed. Further due diligence relating to the wind resource analysis is prudent before accepting this project."

- [redacted] "The wind resource analysis methodology appears to be consistent with industry practice."

The IE noted that a couple shortlisted projects were not included in the independent analysis prepared by Sapere Consulting, including [redacted]

As a result of Sapere's analysis, PacifiCorp made adjustments to the capacity factors of two bids as part of the final evaluation process:

[redacted]

G. Tax Bill Re-Pricing

On December 7, 2017, PacifiCorp notified bidders selected to the initial shortlist that there could be a request for updated pricing to reflect changes to the federal income tax law once the process was complete. On December 15, 2017, the conference committee approved its report on H.R. 1, "The Tax Cuts and Jobs Act." Subsequently, PacifiCorp contacted all shortlisted bidders and requested that they provide updated pricing in response to changes in tax law by 5 PM on December 21, 2017. In PacifiCorp's email, bidders were instructed to identify the specific price or cost components that changed but they should not modify any other items such as schedule, equipment, etc. Table 13 identifies any revisions to project pricing made by shortlisted bidders as a result of the Tax Bill relative to the pricing submitted in the original proposals and the best and final pricing submitted.

Table 13: Revised Pricing to Reflect Federal Tax Bill

Bidder	Project	Bid Type	Capacity (MW)	Original Proposal - First Year Price ($/MWh)	Annual Escalation (%)	Original BTA Proposal - Capital Cost ($/kW)	Best and Final Price – PPA or BTA	Pricing Update to Reflect Tax Bill
Wyoming Proposals								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]

[redacted]

The most significant change in pricing related to the implications of the Tax Bill was the significant increase in PPA pricing for the [redacted] proposals. As Table 12 illustrates, all proposal options by [redacted] were increased significantly. Since several PPA options submitted by [redacted] were ranking high in the shortlist stack, it was expected that the price increase could change the final rankings in the final shortlist evaluations. [redacted]

The final pricing submitted by the shortlisted bidders to reflect the impact of the Federal Tax Bill was used by PacifiCorp to conduct its final shortlist evaluations.

H. PacifiCorp Proposal to Reduce O&M Costs for Larger Wind Turbines

PacifiCorp's evaluation team contacted the IEs in late December, 2017 with a proposal to include lower O&M costs for projects proposing to use the larger wind turbines (in excess of 2 MW and up to 4.2 MW) in their projects. PacifiCorp provided a two-page white paper to the IEs supporting its position that on a per-MW basis, the pricing for a larger turbine should be reduced by 42% as the individual nameplate capacity increases from 2 MW up to 4.2 MW. PacifiCorp recommended that a scaling factor be applied to the cost elements that are covered by the contracted service and maintenance agreement components. This would result in no change to current costs for turbines with nameplate capacities of 2.0 MW, with linearly scaled per-MW cost reductions up to a 4.2 MW nameplate capacity. For a 4.2 MW turbine, this would reduce the cost per turbine down from [redacted].

Merrimack Energy took exception to this recommendation for two reasons:

- The input assumptions, including the O&M cost for the BTA options were already locked-down and these assumptions were applied to the shortlist evaluation results. To make a change in O&M assumptions at this time was not reasonable;
- The IE did not believe the white paper provided by PacifiCorp in support of reducing the O&M costs for larger wind turbines included adequate support or justification for the reduction. The white paper was apparently prepared by PacifiCorp and did not include any third-party support for the magnitude of the change in O&M costs proposed by PacifiCorp.

The proposals that would be affected positively by the proposed reduction in O&M costs included [redacted] While the cost of the smaller turbine options was generally higher than the costs of the same project based on the larger turbines, the generation output based on the smaller turbine configuration was quite a bit higher, which offset all or a significant portion of the capital cost difference when calculating the levelized cost and benefits of each proposal.

I. Final Evaluation Results and Initial Final Shortlist Selection

On January 8, 2018 PacifiCorp provided the final shortlist selection slide deck presentation and evaluation model results for the shortlisted proposals to the IEs for review as stated in the RFP schedule. The evaluation model results for the projects not selected to the final shortlist were sent via USB three days later on January 11, 2018.

The final proposed shortlist included four new wind projects located in Wyoming from three different bidders totaling [redacted]. Of the total capacity, [redacted] MW is in eastern Wyoming with possible interconnection to the Aeolus-to-Bridger/Anticline transmission line. The selected projects included [redacted] MW of capacity under a combined PPA/BTA arrangement, [redacted] MW developed under BTA contracts, one of which is located in Wyoming but is not connected to the Aeolus-to-Bridger/Anticline transmission line, and [redacted] MW of nameplate capacity for a benchmark resource that will be developed under an EPC agreement. The projects selected for the final shortlist are listed in Table 14.

Table 14: Final Shortlist Selection

Bidder	Project Name	Contract	Capacity (MW)	Net Annual Capacity Factor	Total In-Service Capital Cost ($/kW)	PPA Price ($/MWh)
Invenergy	TB Flats I & II	BTA	499	42.46%	[redacted]	[redacted]
NextEra	Cedar Springs	200 MW BTA/200 MW PPA	400	42.78%	[redacted]	[redacted]
PacifiCorp	McFadden Ridge II	Benchmark/EPC	109	44.78%	[redacted]	[redacted]
Invenergy	Uinta	BTA	161	36.42%	[redacted]	[redacted]

As noted, the final evaluation results reflect the [redacted] However, pricing and terms would have to be negotiated. The BTA component of the [redacted] AFUDC costs relative to other proposals which proposed a progress payment structure and thus incurred AFUDC costs based on this structure. This includes the [redacted] The [redacted] project was a high cost project that was selected based on the size of the project relative to the total interconnection capability of the Aeolus-to-Bridger/Anticline transmission line.[33] PacifiCorp's presentation also included an initial project viability assessment for each proposal. PacifiCorp indicated that a final due diligence assessment would occur in parallel with contract negotiations.

The slide deck presentation also included the portfolio results generated by the SO model and the risk assessment results from the PaR model. PacifiCorp informed the IEs that the natural gas price assumptions underlying the SO and PaR model results were based on PacifiCorp's December, 2017 official forward price curve.[34] Natural gas and CO2 price assumptions were based on assumptions adopted from third-party experts.[35] In addition,

[33] The total interconnection capability of the Aeolus-to-Bridger/Anticline transmission line was 1,030 MW. The SO model analysis establishes a constraint of 1,030 MW when selecting project portfolios. Since the [redacted] was the only proposal that would fit in the portfolio within the constraint and provided benefits, it was selected even though its costs were higher than other shortlisted proposals.

[34] [redacted]

the evaluation includes the cost of the Aeolus-to-Bridger/Anticline transmission line, estimated to cost $679 million.

As described in the RFP, the SO model was used to develop bid portfolios for nine price-policy scenarios (3 gas price cases (medium, high and low), and three CO2 cases (medium, high and low)). PacifiCorp used the final pricing based on the bidder's response to the Tax Bill as inputs. In addition to identifying the bid portfolios chosen by the SO model, the present value revenue requirement differential (PVRR(d)) between two system simulations – one with new wind and transmission and one without the wind and transmission – was calculated for each price-policy scenario.

With regard to the SO portfolios, four proposals were selected in all nine cases. These are the projects listed in Table 14 above. For four portfolios (medium gas and high CO2 case plus all high gas cases) the [redacted] proposal was also selected. Based on these results, PacifiCorp advanced the two portfolios to the scenario risk analysis phase of the evaluation using the PaR model. Table 15 provides the SO model results for each portfolio. While this table replicates a table included in PacifiCorp's slide deck, the negative (benefit) values are positive relative to the costs for each of the portfolios.

Table 15: Portfolio Results for SO Model Scenarios

Price-Policy Scenario	Bid Portfolio 1 PVRR(d) (Benefit)/Cost ($ million)	Bid Portfolio 2 PVRR(d) (Benefit)/Cost ($ million)	PVRR(d) (Benefit)/Cost of Bid Portfolio 1 Relative to Bid Portfolio 2
Low Gas, Zero CO2	($198)	($170)	($28)
Low Gas, Medium CO2	($229)	($216)	($13)
Low Gas, High CO2	($347)	($359)	$12
Medium Gas, Zero CO2	($372)	($379)	$7
Medium Gas, Medium CO2	($399)	($407)	$8
Medium Gas, High CO2	($493)	($493)	$0
High Gas, Zero CO2	($692)	($704)	$12
High Gas, Medium CO2	($709)	($720)	$11
High Gas, High CO2	($770)	($782)	$12

The results of the SO evaluation illustrate that significant benefits are expected with either portfolio, totaling $399 million in the case of Portfolio 1 and $407 million for Portfolio 2 under a Medium Gas/Medium CO2 scenario.

PacifiCorp then subjected the two portfolios to the PaR model by evaluating the stochastic-mean and risk-adjusted PaR results. As illustrated in PacifiCorp's presentation, the stochastic-mean and risk-adjusted PaR results show greater benefits overall with Portfolio 1. For example, under the Stochastic Mean PaR scenario risk analysis results, both Portfolio 1 and 2 have the same benefits under the Medium Gas, Medium CO2 case of ($349) million. Portfolio 1 has higher benefits in all cases except the high gas scenarios. Under the Risk-Adjusted PaR scenarios, Portfolio 1 had a benefit of ($367) million while Portfolio 2 showed a benefit of ($366) million. Overall, the results were fairly close with Portfolio 1 having higher benefits in low and medium gas cases and Portfolio 2 having higher benefits in high gas cases. Based on the SO model and PaR results, PacifiCorp chose Portfolio 1 as the least cost, least-risk portfolio to establish the 2017R RFP final shortlist.

PacifiCorp also provided the results associated with SO model runs for Solar Sensitivities based on the bid prices from the 2017S RFP, Wind Repowering Sensitivities, and O&M Sensitivity cases based on projected O&M costs related to increased turbine size.

Appendix G to the IE Shortlist report is the January 8, 2018 initial Final Shortlist presentation deck as described in this section of the report.

In reviewing the updated model results from the RFP Base or spreadsheet model sent by PacifiCorp along with the final shortlist evaluation results, Merrimack Energy noticed that the benefit associated with the PTC had declined quite significantly for BTA projects. For example, for the [redacted] in the initial shortlist evaluation results. PacifiCorp indicated this was a result of the new Tax Bill impacts. The IE questioned why PPAs would not be more competitive or even selected in the portfolios since the economics of BTAs and PPAs for initial shortlisting results were so competitive with a small differential in overall benefits on a $/MWh basis.

In a conference call with PacifiCorp on January 9, 2018, both IEs raised this issue. PacifiCorp reminded the IEs that in developing its model inputs for the SO model, the PTC values and benefits are included as nominal dollars because this reflects how the benefits would be recovered in rates. The capital cost inputs for the benchmarks and BTAs are based on real levelized costs for the period 2017-2036, consistent with the IRP methodology. The IEs raised the issue that this approach could bias the evaluation results towards BTA options if only a portion of the capital costs associated with the benchmarks and BTAs are recovered during the 20-year evaluation period, since these projects have a 30-year life and capital cost recovery period. The Oregon IE asked PacifiCorp to run a sensitivity case in which the PTC values would also be levelized as opposed to treating the PTCs on a nominal dollar basis to assess the impact of this methodology for portfolio selection.

The IEs requested that PacifiCorp set up a conference call on January 12, 2018 to discuss the results of the sensitivity analysis requested by the Oregon IE and to address any other questions from the IEs. Merrimack Energy sent four additional questions to PacifiCorp prior to the call focused on the impact of the lower PTC values, the impacts of a 20-year (i.e. 2017-2036) analysis vs a 30-year analysis, the basis of the methodology to treat the capital costs of utility-ownership options as inputs to the SO model using a real levelized cost methodology over the 2017-2036 timeframe only, and the basis for reducing the net capacity factor for the [redacted].[36]

During the conference call on January 12, 2018, PacifiCorp reported on the results of the evaluation it conducted based on the Oregon IE's request. The results of the SO model indicated that based on use of levelized cost for PTCs a portfolio that included the [redacted] instead of the [redacted] would be selected. PacifiCorp, however, refuted the basis for evaluating the PTCs on a levelized cost basis since PacifiCorp would flow through all the PTC benefits to customers as incurred during the initial 10-year period to reduce customer costs in the near term. PacifiCorp also provided a 30-year analysis of the costs and benefits of the initial portfolio and updated portfolio with the [redacted] to demonstrate that the original portfolio would still provide greater benefits over a 30-year timeframe. Furthermore, PacifiCorp stated that the initial portfolio would provide near term savings as a result of passing through the PTC benefits over the initial 10-years of the project term.

On January 13, 2018 PacifiCorp contacted the IEs to inform the IEs that it had uncovered errors in its analysis while preparing materials for its regulatory filing due on Tuesday, January 16, 2018. As reported by PacifiCorp to the IEs via email, the first issue was that the SO model and PaR analysis had overstated the energy output from the [redacted] PacifiCorp noted that it had adjusted the capacity factor for the bid by [redacted] at the recommendation of Sapere Consulting. This adjustment was correctly reflected in the net bid costs (including PTC benefits) entered into the models, but the energy produced by the project and delivered to the system did not reflect the 8% adjustment. This meant that NPC benefits associated with this bid were overstated. The same issue also applied to [redacted], which also received an [redacted] net capacity factor discount.

The second issue was that PacifiCorp discovered that the [redacted] did not include sales tax. [redacted]. Based on the sales tax applicable to PacifiCorp's own wind repowering project, [redacted]. PacifiCorp re-ran the SO model for the medium/medium and low/zero price-policy gas/CO2 scenarios, incorporating fixes for the [redacted] and adding sales tax estimates to the [redacted]. In both of the price-policy scenarios, the SO model continued to select the [redacted] However, as a result of the sales tax impact, the SO model now selected the [redacted]. In the email to the IEs, PacifiCorp indicated that it reran the SO studies for all nine price-policy scenarios reflecting the corrections and are also re-running the PaR studies. PacifiCorp stated that as a result of this revision, it planned to include the results of these studies in their

[36] According to the Sapere report, "given the uncertainties and limitations of the wind resource analysis proposed, it is Sapere's opinion that the [redacted] is likely overstated by as much as 6% to 8%, and as a result, the Project has a material likelihood to not perform as proposed."

application to be filed on Tuesday, January 16, 2018, reflecting the inclusion of the [redacted]

The IEs were required to complete their review of the final shortlist evaluation and selection and provide its opinion of the final shortlist selection on January 15, 2018. Merrimack Energy requested that PacifiCorp provide the assessment of the [redacted] which was not included in Sapere's report, even though the project was selected for the shortlist.[37] Merrimack Energy also provided written comments to PacifiCorp and the Division regarding the final shortlist selection. Merrimack Energy had reached the following conclusion regarding shortlist selection:

> "Based on the questions identified by the IEs, the last-minute revisions to the analysis to address errors in inputs, and uncertainty over the reasonableness of the evaluation methodology, Merrimack Energy feels that a logical solution would be to include the [redacted] as an option to the [redacted], which total approximately [redacted]. While we recognize that there appears to be significant benefits associated with the combination of new wind and transmission and that the methodology appears to be the same methodology used in the Company's IRP, we feel the final portfolio selection should be scrutinized further and the risks associated with each portfolio option addressed in more detail. Since the size of the portfolio alternatives proposed are essentially the same, such a selection should not jeopardize the timing of the application or affect the assessment of the Aeolus-to-Bridger/Anticline transmission option at the regulatory level."

The complete written comments document provided by the IE to PacifiCorp on January 15, 2018 is included as Appendix H to the IE Shortlist report.

On January 16, 2018, PacifiCorp provided the IE Supplement 2 to the Wind Assessment Report prepared by Sapere Consulting. [redacted] project, Sapere concluded:

> "The wind resource analysis provided by [redacted] seems reasonably consistent with industry practice at a high level. While the analysis and proposal describe a wind project that would behave in a manner relatively consistent with other operating projects in this region, there is a slight concern raised by the somewhat optimistic wake losses of 4.9 and 5.3 percent. Sapere's opinion is that the resource assessment seems reasonable as proposed, but the wake losses may be optimistic and should be reviewed by PacifiCorp."

On January 19, 2018, PacifiCorp provided a Revised Final Shortlist Presentation to the IEs and also scheduled a conference call to discuss the presentation. As noted above, [redacted]

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[37] It is important to note that PacifiCorp could not just rely on the analysis completed by Sapere on the Invenergy TB Flats I and II project since the benchmark and Invenergy proposals for TB Flats I and II proposed different equipment and had a slightly different capacity amount.

[redacted] connecting to the proposed Aeolus-Bridger/Anticline transmission system. The revised final shortlist is projected to deliver at least [redacted] in present value revenue requirements benefits for customers under the medium natural gas price and medium CO2 price input cases under the SO model runs and [redacted] under the two PaR model runs. The Revised Final Shortlist Presentation is included as Appendix I to the IE Shortlist report.

PacifiCorp also addressed the proposal of the IEs to consider a PPA bid in the final portfolio. According to PacifiCorp's analysis, based on PacifiCorp's on-going review of the transmission interconnection queue shows that the PPA bid [redacted] will be unable to achieve interconnection without construction of elements of the Energy Gateway transmission project included in PacifiCorp's long-term transmission plan (i.e. Gateway West and Gateway South). In other words, even if the [redacted] were selected, there are a number of projects in the interconnection queue before this project to result in the conclusion that the project would not be able to interconnect to the Aeolus-Bridger/Anticline system. PacifiCorp concluded that considering both the timing and cost for such an interconnection, it is not reasonable to expand the final shortlist to include this PPA bid. PacifiCorp also raised the issue that because the [redacted] was also lower in the queue, the above concerns related to interconnection to the Aeolus-to-Bridger/Anticline was applicable to [redacted] as well. However, PacifiCorp noted that given [redacted], it may be possible to use one of the advancement provisions in PacifiCorp's Open Access Transmission Tariff. PacifiCorp concluded with regard to [redacted] that because of [redacted] and relative queue position, it is reasonable to keep the project on the final shortlist pending receipt of additional information.

Table 16 provides the revised final results (as of January 19, 2018) for the SO and PaR cases for the final portfolio. While the PVRR(d) benefits are lower than under the previous portfolio, the results still illustrate significant positive benefits.

Table 16: Revised Portfolio Results for SO Model Scenarios

Price-Policy Scenario	Final Portfolio – SO Model PVRR(d) (Benefit)/Cost ($ million)	Final Portfolio Stochastic-Mean PaR PVRR(d) (Benefit)/Cost ($ million)	Final Portfolio Risk-Adjusted PaR PVRR(d) (Benefit)/Cost ($ million)
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)

PacifiCorp also addressed two of the IEs concerns raised in discussions on shortlist evaluation and selection. The first issue dealt with the application of the PTCs in the evaluation methodology. As noted, PacifiCorp's analysis assumes that the PTC inputs to the SO model would be based on nominal dollar values since the actual benefits would be flowed through to customers. The Oregon IE requested a sensitivity where the PTC benefits produced by BTA and benchmark options would be levelized over the full 30-year life of the project. A second issue raised by the IEs was whether the term of the analysis through 2036 (approximately 16 years) and the real levelized cost treatment for capital revenue requirements adequately reflects all the capital costs associated with utility ownership options over a thirty-year project life. In response, PacifiCorp completed an analysis of the expected benefits and costs through 2050 comparing the results of PacifiCorp's selected portfolio and the IE sensitivity case. In its presentation, PacifiCorp concluded that the PVRR(d) benefits through 2036 from the final shortlist portfolio total $343 million and the benefits from the IE Sensitivity with the PPA included in the bid portfolio total $277 million. Through 2050, the benefits from the final shortlist bid portfolio of $223 million are closely aligned with the IE Sensitivity bid portfolio that provides an estimated $224 million in benefits through 2050. The revised shortlist portfolio provides greater near-term benefits.[38]

PacifiCorp also informed the IEs that the Company had publicly stated that it was re-studying the projects in the interconnection queue that have existing studies, but have not signed LGIAs to reflect the revised assumptions that Segment D.2 would be in service by the end of 2020. PacifiCorp stated that its assumption at this point is that the restudies are unlikely to show that projects lower in the interconnection queue will be able to interconnect without Gateway West and Gateway South. This is true of [redacted] as well as other RFP bidders with low queue positions.

On January 31, 2018, PacifiCorp provided seven System Impact Studies for projects in its interconnection queue that were part of the restudy process due to the staging of the Energy Gateway West project, whereby the Aeolus-to-Bridger/Anticline D.2 segment of the project is now expected to come online in 2020. PacifiCorp also listed the conclusions resulting from this restudy effort, including:

- The [redacted] triggers Energy Gateway South [redacted], top of page 8)[39];
- It is accurate to assume that any project behind the [redacted] with an interconnection queue position greater than [redacted] would also trigger Energy Gateway South, which included [redacted] The

[38] This analysis compares the PVRR of Project Net Costs relative to System Impacts where Project Net Costs include: (1) Transmission Project Capital Recovery, (2) Incremental Transmission Revenue, (3) Capital Recovery – Wind, (4) Network – Wind, (5) O&M costs; (6) PTC benefits, (7) PPA costs, and (8) Terminal value. System Impacts include: (1) Net Power Costs (savings), (2) Emissions, (3) Changes in DSM, and (4) System Fixed Costs.
[39] The SIS report states "Additionally, [redacted] triggers the need for the Transmission Provider's planned Energy Gateway South Project. This project consists of a new 400-mile 500 kV transmission line from the planned Aeolus substation in Wyoming to the Transmission Provider's existing Clover substation in central Utah, with ancillary improvements".

restudy work also supports an increase in total interconnection capacity created by segment D.2 from 1,270 MW to 1,510 MW;

- After reserving capacity for the 240 MW QF project that has a signed interconnection agreement, the amount of interconnection capacity available for bids with interconnection queue positions or project locations that are capable of interconnection with just [redacted]
- Eliminating bids located behind the [redacted] with queue positions greater than [redacted] leaves the bid alternatives for [redacted] PacifiCorp is still reviewing SO model studies to assess how this affects the final shortlist, but with the increased interconnection capacity available and restricted to the bids listed above, it looks like the final shortlist would be modified by swapping out the [redacted]. All other selections would be unchanged.

PacifiCorp also stated that it was targeting early in the first week of February to send out a full round of the latest SO model and PaR model studies. PacifiCorp and the IEs also scheduled a call for February 2, 2018 to review the slide deck and latest results.

During the call on February 2, 2108 PacifiCorp noted the cost of the Aeolus-to-Bridger/Anticline would be the same. Also, the inclusion of the [redacted] as a lower cost and larger project than [redacted] should increase the overall benefits of the portfolio.

The IEs, on the other hand, expressed some frustration that the bid selection process ended up being limited to selection of only those projects with favorable queue positions, which included the [redacted]. All other proposals submitted were behind the interconnection queue constraint and would have no chance of being selected.

On February 5, 2018, PacifiCorp contacted the IEs via email and informed the IEs that based on technical discussions with [redacted] and the modeling of their turbines in power flow studies, a risk had been identified that may require installation of a synchronous condenser at the Aeolus Substation. This risk translates into the potential for additional costs associated with bid selections that rely on the [redacted]. Considering that the [redacted] bids are available with [redacted] and [redacted] PacifiCorp is taking a little extra time to analyze the cost trade-offs between bid portfolios with and without [redacted]. PacifiCorp wanted to make sure that its analysis factors this risk into the updated final shortlist before sending the final results. PacifiCorp also indicated it would also include a sensitivity analysis assuming the [redacted] as a 100% PPA.

PacifiCorp stated it expected to send its findings to the IE by Monday, February 12, 2018. PacifiCorp also indicated it planned to delay its supplemental filing in Utah until Friday, February 16, 2018 and will file the final shortlist in Oregon on February 16, 2018 as well.

J. Final Evaluation Results and Updated Final Shortlist Selection

On February 13, 2018 PacifiCorp provided the updated final shortlist selection slide deck presentation and evaluation model results for the shortlisted proposals to the IEs for review. The Updated Final Shortlist slide deck is included as Appendix J to the IE Shortlist Report.

With the higher interconnection limits, the updated final shortlist included four new wind projects located in Wyoming from three different bidders totaling 1,311 MW. Of the total capacity, 1,150 MW is in eastern Wyoming with possible interconnection to the Aeolus-to-Bridger/Anticline transmission line. [redacted] but is not connected to the Aeolus-to-Bridger/Anticline transmission line. Table 17 below provides the updated summary of the final shortlist of projects.

Table 17: Updated Final Shortlist Selection

Bidder	Project Name	Contract	Capacity (MW)	Net Annual Capacity Factor	Total In-Service Capital Cost ($/kW)[40]	PPA Price ($/MWh)
PacifiCorp	TB Flats I & II	Benchmark/EPC	500	38.68%	[redacted]	[redacted]
NextEra	Cedar Springs	200 MW BTA/200 MW PPA	400	42.78%	[redacted]	[redacted]
PacifiCorp	Ekola Flats	Benchmark/EPC	250	37.42%	[redacted]	[redacted]
Invenergy	Uinta	BTA	161	36.42%	[redacted]	[redacted]

Table 18 provides the updated final shortlist results (as of February 12, 2018) for the SO and PaR cases for the final portfolio. Based on the substitution of the larger and lower cost [redacted], the SO and PaR results are more robust, with higher benefits associated with the updated final shortlist selected. For example, the medium gas, medium CO2 case now shows a benefit of [redacted] in PVRR(d) benefits relative to the revised shortlist results from January 19, 2018 which illustrated a benefit of [redacted] as depicted in Table 16 above.

[40] Total In-Service Capital Cost includes all equipment/capital costs, direct assigned interconnection costs, Wind owner's capital cost, property taxes, AFUDC, contingency, and interconnection network upgrade costs.

Table 18: Updated Portfolio Results for SO Model Scenarios

Price-Policy Scenario	Final Portfolio – SO Model PVRR(d) (Benefit)/Cost ($ million)	Final Portfolio Stochastic-Mean PaR PVRR(d) (Benefit)/Cost ($ million)	Final Portfolio Risk-Adjusted PaR PVRR(d) (Benefit)/Cost ($ million)
Low Gas, Zero CO2	($185)	($126)	($132)
Low Gas, Medium CO2	($208)	($155)	($164)
Low Gas, High CO2	($370)	($313)	($331)
Medium Gas, Zero CO2	($377)	($295)	($310)
Medium Gas, Medium CO2	($405)	($333)	($362)
Medium Gas, High CO2	($489)	($424)	($445)
High Gas, Zero CO2	($699)	($545)	($572)
High Gas, Medium CO2	($716)	($579)	($609)
High Gas, High CO2	($781)	($671)	($705)

The Updated Final Shortlist slide deck also includes updated sensitivity results for solar from the 2017S RFP, wind repowering sensitivity, O&M sensitivity, sensitivity case to reflect the impact of selection of a 400 MW PPA from [redacted] as opposed to the split [redacted] option, and turbine equipment sensitivity to reflect the implication of adding a synchronous condenser to effectuate the [redacted] option.

For the 400 MW PPA assessment, PacifiCorp assessed how customer net-benefits are affected by selection of the [redacted] in which the full output of the project is proposed as a PPA. PacifiCorp conducted the analysis over two timeframes: (1) through 2036 similar to the IRP timeframe; and (2) through 2050 to reflect the 30-year life of the asset. In the first case, the shortlist combined portfolio had a PVRR(d) benefit of [redacted] compared to the PPA only with a benefit of [redacted]. For the second case, the combined bid had a benefit of [redacted] compared to the PPA only bid of [redacted]

For the turbine equipment sensitivity case the inclusion of the [redacted] advantage compared to the [redacted] options, assuming a synchronous condenser and other equipment is required.

K. PTC Benefits Associated with the Selected Portfolio

As noted above, the final portfolio includes 1,111 MW of wind projects that will be developed as either a BTA and owned by PacifiCorp or as a benchmark resource owned by PacifiCorp and constructed as an EPC contract and included in rate base. In any case, PacifiCorp has stated that the PTC benefits generated by these projects will be flowed back directly to customers. The PTC benefits associated with the [redacted] will be absorbed by customers due to lower PPA prices. To get a perspective on the magnitude of the PTC benefits that PacifiCorp expects to flow back to customers on a nominal dollar basis, Table 19 includes the expected annual benefits attributed to each project based on PacifiCorp's Base spreadsheet model results. The PTC benefits are based on the PTC value times the level of generation estimated for each project.

Table 19: Annual PTC Benefits - Shortlisted Projects

Year	TB Flats I&II	Cedar Springs BTA	Ekola Flats	Invenergy Uinta	Total
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The results of this assessment illustrate that the value of the PTC benefits to customers on a nominal dollar basis are expected to be approximately [redacted] over the 10-year period.

VI. Assessment of the Solicitation Process

This section of the Report provides our overall assessment of PacifiCorp's 2017R solicitation process with respect to (1) the consistency of the process to the solicitation requirements included in Section R746-420 and Chapter 54 of the Utah Code; (2) consistency of the process with regard to the overall objectives for an effective competitive procurement process; and (3) approach of PacifiCorp in dealing with the issues identified by the IE. In particular, issues associated with the fairness and transparency of the process are addressed in this section.

A. Consistency of the Process With Regard to Utah Statutes

Table 20 includes a detailed description and assessment of the results of the solicitation process relative to each of the applicable solicitation requirements outlined in Section R746-420-3.[41] As illustrated, the IE concludes that the design and implementation of the solicitation process is generally consistent with the solicitation requirements outlined in Section R746-420-3. Any specific issues we have with the process are also described in this Exhibit and are discussed in more detail in the Conclusions section of the report. In our view, overall the process was undertaken in a fair and reasonable manner and in the public interest based on the objectives of the solicitation.

Table 20: Adherence of the Solicitation Process with Section R746-420-3

[41] Since there was no blinding of information requirement associated with this RFP, provisions dealing with blinding were not included.

Solicitation Requirements included in Section R746-420-3	Adherence to Solicitation Requirements
1. General Requirements	
• The solicitation process must be fair, reasonable and in the public interest (Section R746-420-3(1)(a))	In our view, the solicitation process overall was fair, reasonable and generally in the public interest. All bidders and benchmarks were treated the same, had access to the same information at the same time, and had an equal opportunity to compete. Furthermore, the process was a transparent process with active involvement and oversight by the two IEs (Utah and Oregon). The IE agreed with PacifiCorp's decision to classify several bids as non-conforming and also disagreed with PacifiCorp with regard to its proposal to eliminate one other proposal. The public interest standard is served when the competitive process is effectively implemented encouraging a significant response from bidders competing to provide the lowest reasonable cost resources at minimum risk to customers. As we will discuss further, the results of the 2017R RFP targeted on wind resources to take advantage of the PTC benefits, and resulted in significant customer benefits. However, the ability of the solicitation process to account for the cost of other renewable or other resources may have also provided benefits in an overall portfolio.
• The solicitation process must be designed to lead to the acquisition of electricity at the lowest reasonable cost (Section R746-420-3(1)(A))	In our view, the solicitation documents were reasonably transparent and detailed and provided significant information on which bidders could structure their proposals and decide how to compete. The bid evaluation and selection process was designed to lead to the acquisition of wind-generated electricity at the lowest reasonable cost based on the detailed state-of-the-art portfolio evaluation methodology used, the steps taken to achieve comparability between utility cost of service resources and third-party firm priced bids, the flexibility afforded bidders via a range of eligible resource alternatives, and the attempt to allow for equal terms for PPA and BTA resources. The implementation of the solicitation was structured to maintain competition between wind projects at every step of the process. From the perspective of evaluation of the wind resources in combination with the Aeolus-to-Bridger/Anticline transmission line the resource decisions result in significant benefits to customers. However, it is not possible to determine if the wind-only resources offer the lowest reasonable cost without an integrated resource procurement and evaluation process that also includes solar and potentially other resources.
• The solicitation process should consider long and short-term	The 2017R RFP process met these requirements with regard to the high-level bid evaluation and selection

impacts, risk, reliability, financial impacts and other relevant factors (Section R746-420-3(1)(b))	methodology. In the bid evaluation stage, the analysis addressed short and long-term system impacts and risk associated with CO2 costs and gas and power price ranges. The evaluation process also considered the implications of qualitative project viability factors as prescribed in the RFP documents. The IE raised a risk associated with the selection of the benchmark resources and that was attributed to potential cost overruns based on the low capital costs offered.
• Be designed to solicit a robust set of bids (Section R746-420-3(1)(iv))	PacifiCorp has maintained a large database of potential bidders and informed the list of bidders of the issuance of the RFP. PacifiCorp's outreach activities were aggressive and led to a robust set of bids. The IE and DPU were concerned at the outset of the process that there may be limited bidders and suggested options to expand the potential pool of bidders to ensure there was a competitive process. PacifiCorp disagreed with the IE and DPU that the number of bidders may be limited but agreed with the IE and DPU to broaden bidder eligibility which led to a more competitive process in terms of the number of proposals submitted. While there was a robust response, it became obvious later in the process that based on the interconnection queue, bidders who had only initiated project development had little or no chance to compete. The IE requested that PacifiCorp hold a separate workshop for bidders on transmission issues. Perhaps such a workshop would have provided more information to bidders regarding the interconnection process and queue position and may have caused some bidders to consider not bidding if they were aware they had little chance of being successful in this process.
• Be sufficiently flexible to permit the evaluation and selection of those resources or combination of resources determined to be in the public interest (Section R746-420-3(1)(iii))	The IE found that the 2017R RFP was a reasonably flexible process. PacifiCorp allowed bidders to update their pricing after the new Tax Bill was passed to reflect the implications of the bill on their pricing, if material. PacifiCorp generally allowed bidders to be flexible in their responses, worked with bidders to conform their proposals, and made revisions to the process at the suggestions of the IEs, including revising the timing for bidder submission of the Commitment Letter. PacifiCorp also included analysis in the evaluation process requested by the IEs. The solicitation process also resulted in selection of one proposal, the Invenergy Uinta project, that provided customer benefits and was not dependent on the construction of the Aeolus-to-Bridger/Anticline transmission system.
• Be timely in the sense of ensuring adequate time is allotted to undertake the analysis and secure the resource (Section	Merrimack Energy did have some issues with regard to the timing for undertaking some of the key activities. The schedule in itself was tight and the company did not maintain the proposed schedule for the 2017R RFP very well at the end of the final shortlisting process due to

R-746-420-3(1)(v))	errors in the analysis and updated and revised evaluation results. PacifiCorp did make a valuable adjustment in the process by allowing Wyoming and non-Wyoming bidders to submit their proposals at different times. This allowed non-Wyoming bidders more time to prepare and submit proposals.
2. Screening Criteria – Screening in a Solicitation Process	
• Develop and utilize screening and evaluation criteria, ranking factors and evaluation methodologies that are reasonably designed to ensure the process is fair, reasonable, and in the public interest in consultation with the IE and Division Section R746-420-3(2)(a)).	The RFP included a description of the screening and evaluation criteria, the evaluation methodologies, and other information to ensure the process was fair, reasonable and in the public interest. In our view, the evaluation criteria and evaluation methodologies were consistently applied to all proposals and benchmarks and are consistent with standard industry practices. Furthermore, the transparency of the criteria allowed bidders to reflect the specific criteria in their proposals. The IE recommended that PacifiCorp reconsider a few of the qualitative criteria to reflect project viability in the assessment and the Company agreed to review and adjust the criteria.
• In developing the screening and evaluation criteria, the utility shall consider the assumptions in the utility's most recent IRP Section R746-420-3(2)(c)).	The Company used a consistent set of assumptions generally based on the assumptions used in the most recent IRP. The assumptions were consistent (e.g. fuel and CO2 costs), were of recent vintage, and were locked down prior to receipt of bids. PacifiCorp provided the assumptions and inputs with back-up support to the IEs prior to receipt of the bids. PacifiCorp did use updated gas and CO2 assumptions for the final shortlist evaluation results for the SO and PaR modeling activities.
• The utility may but is not required to consider non-conforming bids and will provide advance notice to the IE of its decision regarding non-conforming bids (Section R746-420-3(2)(d))	There were a few non-conforming bids eliminated from consideration in the evaluation process. PacifiCorp identified the bids it considered non-conforming to the IEs before notifying the bidders to allow for IE review of the decision. The IEs were in agreement with PacifiCorp's decision to classify some bids as non-conforming since the bids eliminated did not meet minimum eligibility requirements or were not wind-only bids. PacifiCorp notified the identified bidders after discussions with the IEs.
4. Disclosures – Benchmark Options	
• Identify whether the Benchmark is an owned option or a purchase option (Section R746-420-	PacifiCorp provided four benchmark wind projects, all of which would be utility-owned options. A description of each of the benchmarks was provided in the RFP and in

3(4)(a))	the Bidders Conference presentation.
• If the option is an owned benchmark option, provide a detailed description of the facility, including operating and dispatch characteristics. (Section R746-420-3(4)(b))	PacifiCorp provided the IEs with a complete proposal for each Benchmark option. The Company provided a very detailed description of the benchmark resource, including the technology, cost information, transmission and interconnection, permitting status, site control, etc. The Company provided all the same information as other bidders were required to submit. As noted, benchmark bids and third-party bids were required to provide the same information.
• Assurance from the utility that the Benchmark option will be validated by the IE and that no changes will be permitted unless updates to other bids are permitted. (Section R746-420-3(4)(f))	It was clear to the IE that this was a requirement. The IE participated in discussions with the Benchmark team to ensure the IE had all pertinent information required. The Benchmark team provided very detailed line-by-line information on each resource, and provided all information requested. The IE submitted a report to the Commission as required on its review and assessment of the benchmark resource validating the cost and operating information for each benchmark option but raising some concerns about the capital cost of some of the benchmark resources as being on the low end of the wind project capital cost scale.
• A description and examples of the manner in which resources of differing characteristics or lengths will be evaluated. (Section R746-420-3(4)(c))	Since this is a major issue in any solicitation process, the IE asked PacifiCorp this question during the initial meeting to discuss the bid evaluation methodology and process. The IE was particularly focused on this issue because utility-owned resources with a 30-year life for example, could potentially be competing with 20-year term PPAs. The IE also suggested, and PacifiCorp included in the RFP, options for bidders to offer up to a 30-year PPA. PacifiCorp identified in public documents regarding the RFP that the evaluation would be undertaken over the project life for the initial evaluation but that for the SO model runs, the term of the evaluation would be 2017-2036.
5. Disclosures – Evaluation Methodology	
• The solicitation shall include a clear and complete description and explanation of the methodologies to be used in the evaluation and ranking of bids including evaluation procedures, factors and weights, credit requirements, proforma contracts, and solicitation schedule. (Section R746-420-3(5))	The RFP document contains a detailed description of the methodologies to be used to evaluate the bids, as well as the evaluation procedures, factors, weights, credit requirements, proforma contracts and schedule. Also, similar information was provided to bidders through the Bidders conference presentation. The publicly available IRP was another source of information about the bid evaluation methodology and models to be used since PacifiCorp noted that it intended to use the same methodology for the RFP as it uses for the IRP.
6. Disclosures – Independent	

Evaluator	
• The solicitation should describe the role of the IE consistent with Section 54-17-203 including an explanation of the role, contact information and directions for potential bidders to contact the IE with questions, comments, information and suggestions. (Section R746-420-3(6))	The RFP (e.g. Appendix M) contains a description of the Role of the Independent Evaluator. In addition, the contact information for the Independent Evaluators is provided in the RFP and presentation materials. Bidders were also encouraged to contact the IEs either via Merrimack Energy's website or directly.
7. General Requirements	
• The solicitation must clearly describe the nature and relevant attributes of the requested resources. (Section R746-420-3(7)(b))	In our view, the RFP document was a reasonably transparent document, providing significant information about the nature, attributes, and eligibility of the requested resources including describing the specific requirements for the resources with regard to PTC and transmission. The RFP also provided copies of specific relevant contracts for the specific resource (i.e. PPA, BTA, EPC), and in some cases specifications for resource options.
• Identify the amounts and types of resources requested, timing of deliveries, pricing options, acceptable delivery points, price and non-price factors and weights, credit and security requirements, transmission constraints, etc. (Section R746-420-3(7)(c))	As noted above, the RFP documents were very transparent and detailed and met all the requirements listed in the Rules.
• Utilize an evaluation methodology for resources of different types and lengths which is fair, reasonable and in the public interest and which is validated by the IE. (Section R746-420-3(7)(d))	As noted, one of the major issues in a competitive solicitation process is the development and use by the utility of an evaluation methodology that can effectively account for the evaluation of bids with different terms, resource characteristics, and technologies. In our view, while all of the models and methodologies used by PacifiCorp are used for the IRP process evaluation of resources, the IEs were concerned that the analysis period used for the SO model evaluation was less than 20-years (i.e. 2017-2036), with the possible implication that 30-year BTA options would have an inherent competitive advantage since not all costs would be accounted for in the evaluation. The IEs asked PacifiCorp to conduct analysis over a 30-year period to ensure the overall results would not change. Overall, the results indicated that there did not appear to be an inherent advantage associated with a utility-ownership bid due to the shorter evaluation period for purposes of evaluating and selecting a portfolio of resources. The net benefits approach used may eliminate the costs for a longer-term resource but also eliminates the revenue side of the equation, which

	would likely be escalating over time. All of the models are either industry standard models and/or have been applied and refined for similar applications over time, including PacifiCorp's IRP methodology and process. The SO and PaR models are industry standard models that have been tested in the market. The RFP Base Model allows for a consistent and fair evaluation of bids of different technologies and terms and is a reasonable tool for initial evaluation of bids.
• Impose credit requirements that are and other bidding requirements that are non-discriminatory, fair, reasonable and in the public interest. (Section R746-420-3(7)(f))	Overall, the IE was of the opinion that the level, type and schedule for posting security were generally reasonable and consistent with industry standards. The IEs did request that PacifiCorp include a description of the credit methodology in the RFP, which PacifiCorp agreed to include. The issue that was problematic was the requirement that bidders had to provide a commitment letter from their credit support provider if selected for the shortlist. This was inconsistent with industry standards and was contrary to the way bidders approach project development. This issue was resolved by Merrimack Energy and PacifiCorp and the requirement for a commitment letter was now pushed back until after final shortlist selection. Several bidders raised this issue initially but dropped their concerns once the requirement was revised.
• Provide reasonable protection for confidential information. (Section R746-420-3(7)(i))	The Company was diligent in ensuring that confidential information was shared only with members of the internal team, IEs, Division and other parties as required. There did not appear to be any evidence where any violations of confidentiality took place. The Company took all reasonable measures to protect confidential information.
8. Process Requirements for a Benchmark Option	
• Evaluation team may not be members of the Bid team or communicate with the Bid team about the solicitation process. Section R746-420-3(8)(a))	The RFP and Code of Conduct clearly described the teams and requirements for each team. Each team member was instructed in writing on the separation of functions and the Code of Conduct requirements. Team members also went through an in-house training process, which was witnessed by the IE and DPU staff. These requirements were maintained throughout the process. To the best of our knowledge, there were no violations by any team members. Furthermore, the company identified the protocols clearly to bidders in its Bidders conference presentation.
• The names and titles of each member of the Bid team, non-blinded personnel, and evaluation team shall be	The names of individual team members were provided to the IEs as required along with the team to which they were assigned.

provided to the IE. (Section R746-420-3(8)(b))	
• All relevant costs and characteristics of the Benchmark options must be audited and validated by the IE prior to receiving any of the bids. (Section R746-420-3(8)(h))	PacifiCorp provided the benchmark resources to the IE one week before Wyoming bids were due. The IE audited the Benchmark resources, conducted calls with the Benchmark team, and prepared a report on the findings. The report was submitted to the Commission and Division on November 2, 2017, shortly after receipt of bids due to the quick timeframe for this solicitation.
• All bids must be considered and evaluated against the Benchmark option on a fair and comparable basis. (Section R746-420-3(8)(i))	PacifiCorp's Benchmark resources were submitted before other proposals were received, provided the same information in their proposal documents as all other bidders, and were evaluated based on the same evaluation methodology and steps. For both shortlist and final evaluation, all eligible proposals, including the benchmarks were equitably and consistently evaluated. The IE did identify a few examples where one of the [redacted] resources, the [redacted], was not specifically included in PacifiCorp's slide deck initial shortlist presentation or was subject to the evaluation of the generation profile undertaken by PacifiCorp's consultant, Sapere Consulting. These oversights were identified earlier in this report.
9. Issuance of a Solicitation	
• The utility shall issue the solicitation promptly after Commission approval. (Section R746-420-3(9)(a))	The RFP was approved on September 22, 2017 and issued on September 72, 2017.
• Bids shall be submitted directly to the IE. (Section R746-420-3(9)(b))	The initial bids were submitted to the Utah IE at its California office. Any updates were provided by PacifiCorp via email.
• The utility shall hold a pre-bid conference (Section R-746-420-3(9)(c))	PacifiCorp held a pre-bid conference on October 2, 2017.
10. Evaluation of Bids	
• The utility shall provide all data, models, materials and other information used in developing the solicitation, preparing the Benchmark option, or screening, evaluating or selecting bids to the IE and the Division staff.	PacifiCorp provided all the input data prior to receipt of bids, conducted meetings with the IEs and Division to review the models, model methodologies, and basis for input forecasts. In addition, the Company's Benchmark team provided detailed information on the benchmark resources to the IEs and responded in a timely manner to questions.
• The IE shall pursue a reasonable combination of auditing the utility's evaluation and conducting its own independent evaluation in consultation with the Division.	Given the timing of the evaluation process, the IE primarily audited the Company's analysis rather than undertaking its own independent evaluation. In other bidding processes, the IE usually undertakes an independent non-price and at times an initial price evaluation process to verify short list selection. In this case, the IE conducted a thorough review and assessment

	of PacifiCorp's evaluation results and model outputs and asked questions if any information seemed inconsistent.
• The IE shall have access to all information and resources utilized by the utility in conducting its analyses. The utility shall provide the IE with access to documents, data, and models utilized by the utility in its analyses.	PacifiCorp was diligent in providing information it compiled on each bid and also was responsive to any requests for information asked by the IE or for completion of studies requested by the IE. PacifiCorp was very forthcoming with this information and at no time did the IE feel access was restricted or limited.
• The Division and IE may ask the PacifiCorp Transmission Group to conduct reasonable and necessary transmission analyses concerning bids received.	PacifiCorp set up conference calls with the IE and PacifiCorp Transmission personnel to discuss any issues the IE may have regarding transmission and interconnection. PacifiCorp was responsive to the IEs requests in this area.

B. Consistency of the Process With Regard to an Effective Competitive Solicitation Process

Merrimack Energy has developed a set of criteria that we generally use to evaluate the performance of the soliciting utility in implementing a competitive solicitation process. In this section, the performance of PacifiCorp is assessed in more detail. [42]

This 2017R RFP process was a detailed process, encompassing the development of the RFP through selection of the final shortlist. Based on Merrimack Energy's experience with competitive bidding processes and observations regarding such processes, the key areas of inquiry and the underlying principles used by Merrimack Energy to evaluate the bid evaluation and selection process include the following:

1. Were the solicitation targets, principles and objectives clearly defined?

2. Did the solicitation process result in competitive benefits from the process?

3. Was the solicitation process designed to encourage broad participation from potential bidders?

4. Did PacifiCorp implement adequate outreach initiatives to encourage a significant response from bidders?

5. Was the solicitation process consistent, fair and equitable, comprehensive and unbiased to all bidders?

6. Were the bid evaluation and selection process and criteria reasonably transparent such that bidders would have a reasonable indication as to how they would be evaluated and selected?

[42] It should be noted that there is overlap with the criteria and assessment of PacifiCorp relative to the criteria since some of the criteria are consistent with the requirements identified in the Utah Statutes.

7. Did the evaluation methodology reasonably identify how quantitative and qualitative measures would be considered and applied?

8. Did the RFP documents (i.e. RFP, Attachments, Appendices, Pricing Form and Model Contracts) describe the bidding guidelines, the bidding requirements to guide bidders in preparing and submitting their proposals, and the bid evaluation and selection criteria.

9. Did the utility adequately document the results of the evaluation and selection process?

10. Did the solicitation process include thorough, consistent and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process.

11. Did the solicitation process ensure that the Power Contract was designed to minimize risk to the utility customers while ensuring that projects selected can be reasonably financed.

12. Did the solicitation process incorporate the unique aspects of the utility system and the preferences and requirements of the utility and its customers.

The implementation of the 2017R RFP process relative to the characteristics identified previously is described below. Merrimack Energy has been involved in all aspects of the solicitation process.

1. Solicitation Targets

The RFP document clearly defined the amount of wind generation capacity requested, the timing for providing the capacity, the type of products and product characteristics required, the duration of potential contracts, and the amount of wind generation capacity the Company expected to shortlist. As noted, PacifiCorp actually included more generation capacity on the shortlist than it expected to select due to the competitive nature of the responses.

2. Competitive Benefits

Competitive benefits can result from a process that encourages a large number of suppliers in combination with reasonable bidding standards and requirements and a balance of risk in the associated contracts such that the process leads to robust competition, lower prices for consumers, limited risk and reliability.

PacifiCorp's solicitation process encouraged a reasonable response from the market, with large and significant wind project development firms participating in the process. The

2017R RFP resulted in a robust response from bidders with the amount of unique capacity (based on the largest bid from each bidder) exceeding 5.5 times the amount of generating capacity requested. The proposals were very competitive from the beginning with very close ranking of proposals at the initial shortlist stage all the way through to final evaluation and selection. The final result of the solicitation was that the overall benefits to customers based on the RFP were approximately [redacted] in NPV value in the medium gas, medium CO2 case.,

3. Broad Participation from Potential Bidders

As noted above, the process encouraged a reasonable number of proposals as well as different contract and project structures. As we noted, PacifiCorp received 72 proposals from well-known, highly experienced and highly capitalized wind project developers. In addition, PacifiCorp received Wyoming and non-Wyoming bids, proposals that included PPAs, BTAs, benchmarks and combination bids. Some project developers offered both PPA and BTA options for the same projects. Proposals also included projects located in Wyoming that would interconnect with the new Aeolus-to-Bridger/Anticline transmission project as well as wind projects located in other areas of PacifiCorp's system.

4. Outreach Initiatives

PacifiCorp has done a very effective job of maintaining communications with bidders and providing information to prospective bidders in their competitive solicitation processes. PacifiCorp has a large database of potential bidders and actively marketed the RFP to those prospective bidders. PacifiCorp also maintains a section on their website devoted to open RFPs which bidders could easily access. Also, through the solicitation process, PacifiCorp initiated a number of workshops and conference calls with prospective bidders to inform them of solicitation information.

5. The solicitation process should be consistent, fair and equitable, unbiased, and comprehensive

The principal areas of focus for our assessment of PacifiCorp's 2017R RFP are on the RFP document and on the Company's performance in carrying out the process, from issuance of the RFP document to evaluation and selection of the final shortlist. The key criteria (fair, equitable, consistent and unbiased) are applied to PacifiCorp's implementation of the evaluation and selection process as well as the Company's ability to adhere to the requirements outlined in the RFP document. Therefore, the critique will focus on the implementation of the process rather than specific issues regarding the process.

In our view, PacifiCorp's solicitation process was an open, fair and consistent process in which all bidders had access to the same information at the same time. This was ensured through use of the PacifiCorp website as well as a third-party website (i.e. Merrimack Energy's website) and the role of the IEs. It is our view that the final RFP document generally provided clear and comprehensive information about the requirements of bidders, product definition, schedule of the process, requirements for submitting a proposal, and the opportunities for competing. Bidders should have been able to understand how best to compete in such a process.

While it was our view that the bidding documents and materials were clear and comprehensive, several bidders failed to meet eligibility requirements. It appeared that a few bidders preferred to present unique and creative proposals rather than strictly meeting the requirements of the RFP. A few bidders did not comply with the delivery requirements identified in the RFP (e.g. bidders were required to ensure delivery of the power into the Company system).

The price evaluation methodologies were designed to evaluate bids using the same or consistent set of input parameters, assumptions, and modeling methodologies. This served to ensure a consistent evaluation of bids.

With regard to bias, the most obvious consideration is whether the process favors one type of bidder over another. The IE was concerned that the nature of the evaluation methodology may favor BTA bids at the expense of the PPAs. The results of the initial shortlist, however, appeared to prove that this was not the case since the shortlist was comprised on both BTAs and PPAs. We later again raised the point after bidders provided revised pricing to reflect the impacts of the Tax Bill, that since the value of the PTCs had declined, our expectation was that PPAs should have higher net benefits. Based on the comparison of BTA and PPA proposals using the Base Model, a few PPA options actually did have higher net benefit values. However, these proposals were not selected to the final shortlist due to the project queue position. We also questioned the use of nominal value for the PTCs in calculating the portfolio evaluation results. In addition, we questioned the term of the evaluation (i.e. 2017-2036). Our concern was that all these factors could bias the evaluation results toward BTA options, in which PacifiCorp would be project owner and the costs would be included in rate base. At the request of the IEs, PacifiCorp ran 30-year analysis as well as assessments without using nominal dollars for PTC benefits. The results showed the BTA and PPA for the most competitive projects to be close in value. We feel that there is perhaps a small bias favoring BTAs based largely on the value attributed to the PTCs.

We do not believe any bid had an undue inherent competitive advantage within the parameters of the solicitation process. The eligibility assessment and follow-up information requirements ensured all bidders provided the same information for evaluation purposes. PacifiCorp was inherently focused on ensuring that all bidders competed on an equal footing and had access to the same information.

The solicitation process was well structured to ensure that the information required in the RFP document was linked to the evaluation criteria.

6. Transparency of the Process

The RFP documents, Bidders conferences or webinars, interactive questions and answer process with bidders, and posting of key documents by the Company and IE all led to a process where bidders would have significant information about the process and be aware how to effectively compete. The information required of bidders was clear and concise as witnessed by the generally complete and consistent proposals submitted by bidders. The RFP and related documents were clear on the security and transmission requirements, for example. In conclusion, it is our view that the solicitation process was a reasonably transparent process and in that regard was consistent with or exceeded industry standards.

7. Application of Quantitative and Qualitative Measures

The RFP document clearly articulated the quantitative and qualitative methodologies and requirements associated with the evaluation process. The methodologies and models were clearly described in the RFP and were also consistent with the Company's Integrated Resource Plan. Also, the Pricing Input Sheets and follow-up process with bidders to review their inputs served to ensure bids would be evaluated on a consistent and unbiased manner. These processes took the "guess work" or interpretation out of the process.

8. The RFP Documents should describe the process clearly and provide adequate information on which bidders could complete their proposals

This objective addresses the quality of the documents contained in the RFP package (i.e. RFP, Contracts, Bid Forms required of all bidders, and other Attachments and pertinent information) and the integration among the documents. PacifiCorp's RFP provided considerable detail regarding the information required of bidders, the basis for evaluation and selection, and the criteria of importance. The RFP process clearly provides a direct link between the RFP document, bid form and contracts. In our experience, the 2017R RFP is a very detailed and complete document which provides a significant base of information to guide bidders in developing their proposals. As noted on several occasions, the inconsistency between the requirements for a commitment letter at shortlisting was initially a point of contention in the process. This issue was quickly resolved by PacifiCorp in discussions with the IE.

9. Documentation of Results

The initial and final shortlist evaluation results and selection processes were well documented and supported. The Company provided all necessary supporting information to the IEs, including details on the input assumptions, model outputs, and summaries of results. PacifiCorp provided all the information specifically requested by the IEs including any analysis or modeling results.

VII. Conclusions and Recommendations

A. Conclusions

Merrimack Energy has identified a number of conclusions associated with the 2017R RFP solicitation process undertaken by PacifiCorp. Our conclusions include the following:

- The response to the 2017R RFP for wind resources was very robust with 14 bidders (including PacifiCorp's benchmark resources) submitting 72 different bid alternatives. As a result, the amount of capacity submitted significantly exceeded the amount of capacity requested (up to 1,270) by a factor of nearly 5.5 to 1;

- Bidders submitted a mix of Power Purchase Agreements ("PPA") and Build Transfer Agreements ("BTA"). In addition, bidders offered other creative product solutions as part of the proposals submitted, such as combined BTA/PPA options, different pricing options for the same PPA projects such as fixed pricing and a base price times escalation, BTAs for the same project with different turbines;

- PacifiCorp has generally conformed to the requirements of Rule R746-420 as identified in Chapter VI. All proposals, including the benchmark resources, provided the same level of information as requested in the RFP. PacifiCorp maintained a consistent and equitable evaluation process for all proposals using the same input assumptions for all applicable proposals, PacifiCorp undertook an evaluation methodology and process that was consistent with the methodology adopted for its Integrated Resource Plans ("IRP") and based on the same models used for IRP assessments. The IE found that the benchmark proposals provided the same general information as all other proposals and were evaluated using the same methodology and input assumptions. This conclusion is confirmed by our assessment in Section VI of this report;

- The results of the SO and PaR evaluation on the final revised shortlist illustrate that the pursuit of these wind project to take advantage of the Production Tax Credits ("PTC") should result in significant savings for customers. For the final evaluation results, PacifiCorp estimates that the benefits associated with the portfolio of wind resources is equal to $405 million PVRR under medium gas and medium CO_2 cases. The resulting bid pricing and capital costs overall were lower than the costs included in PacifiCorp's IRP cases, resulting in additional benefits relative to costs than PacifiCorp included in its IRP cases or subsequent assessment. Furthermore, since PacifiCorp intends to flow through all PTC benefits to customers over the first 10 years of the project, the near-term benefits to customers should be significant;
- PacifiCorp generally followed its proposed evaluation and selection process as outlined in the RFP. The primary deviation from the proposed evaluation and selection process was the addition of a third revision to bid pricing to reflect the implications of the federal Tax Bill passed in late December, 2017. PacifiCorp used the pricing provided in response to the request to revise prices as a result of the tax bill or the most recent pricing proposed as the basis for the final evaluation results;

- PacifiCorp required all bidders, including the benchmark resources, to be subject to the same information requirements and conducted a consistent evaluation process with all proposals treated equally in terms of the evaluation methodology and information required of each bidder;
- The IE found that the initial shortlist evaluation and selection was reasonable based on the bid pricing submitted by the Benchmark resources, PPA and BTA options submitted. The size of the initial shortlist exceeded PacifiCorp initial intent since the proposals were generally closely ranked, with little difference in net benefits for the top-rated proposals;

- One of the primary issues the IE is required to address in its assessment of the solicitation process is whether the solicitation process is consistent with Utah Statutes (54-17-101) and is in the public interest taking into consideration whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state, including (1) long-term and short-term impacts; (2) risk; (3) reliability; (4) financial impacts on the affected electric utility; and (5) other factors determined by the Commission to be relevant. In the view of the IE, PacifiCorp's selection of the final portfolio of wind resources is in the public interest based on wind proposals submitted, albeit subject to cost risk associated with the benchmark resources as discussed below. Since PacifiCorp's solicitation is based solely on the solicitation for system wind resources, it is not possible to determine if other resources would have been included in a final least cost, least risk system portfolio, potentially displacing one or more wind resources. The result of this market test for wind was the proposed selection of wind resources that actually provided significantly more customer benefits than PacifiCorp had calculated in its IRP cases. The same could be true for other resources as well.

- The IE is of the opinion that PacifiCorp's selection of the final shortlist of 4 projects totaling 1,311 MW was a reasonable selection based on the constraints identified. The projects selected included PacifiCorp's TB Flats I & II benchmark resource (500 MW); NextEra's Cedar Springs BTA and PPA proposal (200 MW each); PacifiCorp Ekola Flats benchmark resource (250 MW); and Invenergy's Uinta project (161 MW). The first three projects are proposed to interconnect to the Aeolus-to-Bridger/Anticline transmission system, while the Uinta project is located in Wyoming but is not dependent on the Aeolus-to-Bridger/Anticline transmission system;

- The portfolios selected by the SO model are dependent upon the constraints imposed. In this case, the primary constraint was the capacity of the Aeolus-to-Bridger/Anticline line. The initial assessment illustrated that the constraint limited the selection of the resources to the proposals above with the exception of PacifiCorp's McFadden Ridge project being selected instead of Ekola Flats. However, once PacifiCorp Transmission conducted restudies of the System Impact Studies in the queue, the Company found that there was an increase in the interconnection capacity created by segment D2 from 1,270 MW to 1,510 MW. In addition, the studies found that bids with a queue position of Q0713 or greater triggered the requirements for Energy Gateway South. As a result, the SO model could essentially only select the projects that were actually selected based on their position in the queue. While the IE had concerns over the basis of this constraint, these projects were the lowest cost options available. As a note, however, PacifiCorp did not provide technical studies that support the additional capacity of the Aeolus-to-Bridger/Anticline transmission line. PacifiCorp did respond to the question raised by the IE about the cost of the Aeolus-to-Anticline/Bridger line that the cost of the facilities would be the same at $697 million.

- The selection of the benchmark options, notably the selection of the [redacted] poses several risks that need to be scrutinized. The cost of the [redacted] is significantly lower (on a $/kW basis) than a comparable proposal submitted for the same project by [redacted], a sophisticated wind project developer. In addition, the capital cost proposed by PacifiCorp for the [redacted] is significantly lower than any BTA option proposed for similar resources on a $/kW installed basis. The IE had already concluded that the benchmark cost for this project appeared low when compared to market benchmarks in the IE report on the Benchmark resources. In the end, the project capital cost was low compared to actual proposals, with the benchmarks being the lowest cost options proposed by any BTA bidder by a significant margin. Since this project is a cost of service option, the IE suggests that the actual cost of the project be closely scrutinized;
- A common occurrence in the wind industry has been that the actual capacity factors of wind projects have been lower than the projected capacity factors. Such an occurrence for PPA options is not a major issue since the PPA project must conform to the contract requirements for meeting generation required levels or incur penalties. For BTA or Benchmark options, failure to meet the target capacity factor is an issue. For one, the full PTC benefits may not be realized if generation is lower than projected. Failure to meet projected generation levels for these resources results in higher unit costs and raises the question of whether these projects would have been selected if realistic generation profiles were provided. While PacifiCorp retained Sapere to conduct such an analysis to ensure the generation levels and capacity factors are reasonable, the IE feels there is some risk associated with the [redacted] based on the Sapere analysis regarding wake losses. The IE feels that the generation levels of the benchmark and BTA options should be closely monitored to ensure they perform as proposed;
- On the other hand, PacifiCorp has claimed that the O&M costs associated with the larger turbines that it has proposed will incur much lower O&M costs than the O&M costs estimated for the benchmark option. The IE rejected PacifiCorp's proposal to include lower O&M costs for those projects which were using larger wind turbines because the IE felt PacifiCorp did not provide adequate support to base its claim regarding the magnitude of the O&M cost reduction. However, this is an area where PacifiCorp could experience lower costs than project;
- While the IEs suggested that PacifiCorp include another PPA on the final shortlist, PacifiCorp made a compelling case that the queue position of the PPA in

question would result in very high interconnection and network upgrade costs for this project to achieve interconnection to the grid. PacifiCorp indicated that this project could not interconnect to the Aeolus-to-Bridger/Anticline since there were so many projects ahead of it in the queue and that the timing to be interconnected could be substantial. PacifiCorp's conclusion was that this project ([redacted]) would require construction of the Gateway West and Gateway South transmission projects;

B. Recommendations

- Merrimack Energy recommended that PacifiCorp hold a Transmission workshop for bidders as they had for previous solicitations. PacifiCorp agreed but due to the timing of completing the solicitation process, the Transmission workshop was not held. Given the issues with interconnection and changes in transmission interconnection constraints, a Transmission workshop may have shed light for bidders on their chances of success. Instead, at the end of the day, only those projects who had early queue positions had a chance to compete in the process. Essentially this came down to three bidders only: PacifiCorp, Invenergy, and NextEra;

- The IE found that PacifiCorp's Base spreadsheet model was cumbersome to review and evaluate given the large number of tabs and integration between tabs. The IE recommends that PacifiCorp consider simplifying this model;

- The IE feels that PacifiCorp's benchmark project costs are low relative to other wind generation market options. One of the primary concerns of the IE in overseeing a solicitation process with utility-ownership options is the possibility that the utility benchmark option could submit a low-cost bid, be the successful bidder at the lower price, but then experience higher actual costs and seek cost recovery later based on prudency considerations given the different resource characteristics and cost recovery considerations of utility-owned projects. The IE has concluded that the benchmark costs should be scrutinized to ensure the process remains a fair and equitable process with no undue benefits afforded to the benchmark option;

- While the application of a terminal value benefit for utility ownership options was a small factor overall and did not influence final results, the IE feels that the application of a terminal value adder and the methodology to apply terminal value should be considered in more detail in future solicitations;

- As we noted in the discussions surrounding the reassessment by PacifiCorp Transmission regarding the System Impact Restudy process, PacifiCorp Transmission concluded that more interconnection capacity was available on the Aeolus-to-Bridger/Anticline transmission system. While the [redacted] that was selected for the final shortlist had a later queue position and would not be able to interconnect to the system, PacifiCorp was able to then include the [redacted] in the final shortlist once the assessment concluded that more capacity was available. However, we did not see or review the technical studies that supported this conclusion and change in the portfolio. The IE therefore recommends that PacifiCorp provide supporting documentation during the hearings to support its assessment.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-3SR)
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 Surrebuttal Testimony of Rick T. Link

Solar RFP IE Report

May 2018

Privileged and Confidential- Not for Bidder Access

INDEPENDENT EVALUATOR'S CLOSING REPORT ON PACIFICORP'S 2017 SOLAR RFP

Prepared for

PacifiCorp

By

LONDON ECONOMICS

London Economics International LLC
717 Atlantic Ave Suite 1A
Boston, MA 02111

March 29, 2018

Privileged and Confidential – Not for Bidder Access

Independent evaluator's closing report on PacifiCorp's 2017 Solar RFP

Prepared for PacifiCorp by London Economics International LLC

March 29, 2018

London Economics International ("LEI") was engaged by PacifiCorp to serve as Independent Evaluator ("IE") for its 2017 Solar Request for Proposals ("2017S RFP") to ensure that the procurement process is competitive, fair, and managed according to procurement best practices such that the resulting acquisition of solar resources is price competitive. LEI provides this closing report evaluating the initial and final shortlist evaluation process, and the final outcome of the RFP process.

LEI finds that the 2017S RFP was consistent with the RFP documents. It was conducted in a fair and unbiased manner. It attracted a large number of bidders, which helps ensure that any resulting acquisition of solar resources would be price competitive and offer the most potential benefit to retail ratepayers. PacifiCorp's evaluation process was thorough, reasonable, and reflected industry best practices.

In an unusual RFP outcome, PacifiCorp ultimately did not select any of the 2017S RFP bids to the final shortlist, in spite of the potential customer net benefits which PacifiCorp's baseline analysis showed. LEI did not find PacifiCorp's decision not to accept any solar bids to be unreasonable. PacifiCorp believes that bid prices reflected a risk premium based on uncertainty over looming tax and tariff changes during late 2017 and early 2018; the company believes that benefits to consumers will be higher once the uncertainty fades. Therefore, PacifiCorp plans to re-assess the potential benefits of solar resources in its 2019 IRP, with a view to potentially conducting another solar RFP in 2018.

To ensure another robust turn-out of bidders, LEI recommends that PacifiCorp clearly explain to all bidders and to the broader community of solar developers why no bids were chosen for the FSL as part of this procurement process.

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1 Executive summary

On November 15, 2017, PacifiCorp issued a Request for Proposals ("RFP") for solar photovoltaic ("PV") resources ("2017S RFP").[1] PacifiCorp was seeking bids for up to approximately 2,000 MW of aggregate solar capacity in its service territory.

London Economics International ("LEI") was engaged by PacifiCorp to serve as the Independent Evaluator ("IE") for its 2017S RFP to ensure that the procurement process was competitive, fair, and managed according to procurement best practices, such that the resulting acquisition of solar resources would be price competitive and offer the most potential benefit to retail ratepayers.

On January 8, 2018, PacifiCorp selected an initial short list ("ISL") of 25 bids, covering 11 projects, with an aggregate solar capacity of 1,530 MW.[2] The bidders selected in the ISL were given an opportunity to provide best and final pricing, before PacifiCorp considered bids for the final short list ("FSL"). At the conclusion of the FSL evaluation process (discussed in detail in Section 5 of this report), PacifiCorp decided not to select any of the bids to its final short list.

1.1 Key findings

The 2017S RFP was conducted under unusual circumstances. It was conducted at the recommendation of the Utah Public Service Commission,[3] rather than as the result of a business strategy developed in the context of PacifiCorp's then-current IRP. The timing of the procurement was accelerated to match as closely as possible the timing of PacifiCorp's wind RFP (2017R RFP).

In this context, LEI found that:

- **PacifiCorp's 2017S RFP process was conducted in accordance with its RFP documents.** PacifiCorp accurately followed the process that was outlined in its RFP documents. LEI monitored all communications with bidders; PacifiCorp evinced no bias for or against any bidder.
- **PacifiCorp's process for selecting the ISL was conducted in a fair and unbiased manner.** LEI's analysis confirmed that the bids included in the ISL represent the best value considering both price and non-price factors, from all the bids received during the RFP

[1] PacifiCorp. "RFP 2017S Solar RFP Main Document." November 15, 2017. <http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2017S_RFP/Main_Documents/RFP_2017S_SOLAR_RFP_MAIN_DOCUMENT.pdf>

[2] London Economics International LLC. "Independent evaluator's report on initial shortlist selection process: PacifiCorp's 2017S RFP." January 26, 2018.

[3] The Utah PSC order recommending the solar RFP aligned with the Wind RPF COD was issued on September 22, 2017. Docket 17-035-23. <https://pscdocs.utah.gov/electric/17docs/1703523/2969071703523oarfpwsm9-22-2017.pdf>

process. LEI believes that the initial shortlist accurately identified the bids that would result in the largest net benefit to customers across PacifiCorp's service territory.

- **PacifiCorp's quantitative modeling and analysis for the FSL process was fair and reflected industry best practices.** The FSL process included scenario analysis as well as stochastic risk analysis, which reflects industry best practices. PacifiCorp's baseline scenario analysis showed the results for the impact of the solar portfolio on system costs were generally positive. Benefits in the baseline were resilient with respect to stochastic outcomes, too.
- **PacifiCorp's additional sensitivity analysis, applied to stress-test the baseline results, was reasonable.** PacifiCorp additionally stress-tested the top-performing portfolio of bids using two sensitivity analyses. This aspect of the evaluation process was not explicitly communicated to bidders in the RFP documents but was nevertheless consistent with the RFP documents. And in the context of the unusual circumstances of the RFP noted above, LEI believes that it represented a prudent approach. The stress tests showed that projected benefits of the top-performing portfolio might be overstated.
- **PacifiCorp's decision not to award any bids in this RFP was not inconsistent with the process outlined in its RFP documents**, which state "PacifiCorp reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend this RFP in whole or in part at any time."[4]

LEI did not find PacifiCorp's decision not to accept any solar bids to be unreasonable. Without the opportunity to vet a solar procurement in the context of its IRP, it is reasonable that PacifiCorp might have been concerned that the 2017S RFP might not ultimately provide net benefits for its customers. PacifiCorp expressed concern that conditions in the solar market at the time of the bidding reflected uncertainties over tax reform and tariffs on solar equipment.[5] These were reasonable concerns, in light of PacifiCorp's view of market conditions at the time. PacifiCorp believes that the net benefits to its customers of a solar procurement would be higher if it runs a new procurement later in 2018.

1.2 Recommendations

The 2017S RPF was conducted in a manner that was consistent with general procurement best practices, as we have stated above. At the same time, LEI does have recommendations about future RFP processes.

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[4] PacifiCorp. "RFP 2017S Solar RFP Main Document." Page 10. November 15, 2017. <http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2017S_RFP/Main_Documents/RFP_2017S_SOLAR_RFP_MAIN_DOCUMENT.pdf>.

[5] PacifiCorp. "PacifiCorp 2017S Request for Proposals: Final Shortlist. Confidential." March 12, 2018.

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It is possible that by not choosing any winning bidders as part of this RFP that in future procurements, fewer potential bidders might respond. PacifiCorp is considering conducting another solar RFP later in 2018. PacifiCorp has said it expects the market environment for solar to improve over 2018, so that potential bidders in a future RFP can offer lower prices; it also cited the opportunity for solar bids to potentially incorporate storage; and allow more bidders to be further along in the process of permitting, site control, and transmission interconnection. PacifiCorp noted that an RFP initiated in mid-2018 would allow enough lead time for projects to be capable of commercial operation by the end of 2021 (before the Investment Tax Credit ("ITC") declines to its 10% floor).

To ensure that bidders would come back to the table, LEI recommends that PacifiCorp explain clearly and to all bidders, and indeed to the broader solar development community, its rationale for not selecting any bids to the FSL, and underscore that the main issue was the timing (as that seems to be the case) rather than a fundamental concern about solar power.

LEI also suggests that PacifiCorp be more explicit about the stress-testing that it may or may not conduct as part of its bid assessment to be more transparent about how bids will be evaluated as part of the bid evaluation process.

2 Context and objectives

PacifiCorp's 2017S RFP was conducted in response to a suggestion by the Utah Public Service Commission to add solar to PacifiCorp's 2017R Wind RFP that began in 2017.[6] The schedule of the wind RFP was fixed to meet specific regulatory milestones and those could not be extended to accommodate the addition of solar to the wind RFP. Therefore, PacifiCorp offered a separate solar RFP, with a compressed schedule to align with the commercial online date ("COD") established in the 2017R Wind RFP, so that PacifiCorp would be able to solicit wind and solar offers for the same COD.

2.1 The role of the Independent Evaluator

The IE's role is to ensure the fair, proper, and consistent evaluation of proposals received. See Section 8 (Appendix B) for additional details of the IE's role, as prescribed by PacifiCorp. The involvement of an IE was the option of PacifiCorp, as an IE was not required. This points to a disposition on the part of PacifiCorp to conduct business in a transparent and open manner, which is a credit to PacifiCorp

LEI's task was not to create the ISL or the FSL, but to evaluate the process to ensure PacifiCorp's bid evaluation process was fairly applied across the bidders and resulted in an FSL which provide the most potential value for PacifiCorp customers. LEI undertook the following activities in evaluating the RFP process and outcomes:

- Reviewed and assessed the draft RFP documents;
- Ensured the same information was provided to all bidders;
- Participated in bidder's conference;
- Reviewed bids' compliance with Minimum Eligibility Requirements;
- Monitored all communications between PacifiCorp and bidders after receipt of bids;
- Ensured there was no bias in the procurement process that unjustly favored bids;
- Reviewed in detail PacifiCorp's proprietary models used in the bid evaluation process;
- Assessed the ISL and FSL process to determine if the evaluation criteria, methods, and models were consistently and appropriately applied to all bids and were performed as laid out by PacifiCorp in the RFP; and
- Documented the development of the 2017S RFP process with three reports: First Status Report, ISL Report, and the Closing Report.

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[6] Public Service Commission of Utah. "Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources." November 9, 2017. Docket no. 17-035-23

3 PacifiCorp's evaluation process

This section summarizes PacifiCorp's evaluation process. LEI found this process to be consistent with PacifiCorp's RPF documents and industry best practices, and fair to bidders.

PacifiCorp's bid evaluation process began with establishing whether a bid met the minimum eligibility requirements. The eligibility criteria help to ensure ratepayers would not be stuck with projects that would encounter unnecessary delays—and to ensure a bidder had the wherewithal to complete a project. Bids that passed this threshold were then considered for the ISL. Bids that made it to the ISL were then further analyzed to project their potential impacts on the PacifiCorp system, to arrive at a projection of net benefits.

3.1 Minimum eligibility requirements

Before performing ISL evaluation, PacifiCorp eliminated 35 bids which clearly did not meet the minimum eligibility criteria laid out by PacifiCorp. Key minimum requirements were:

- demonstration of ability to meet the commercial online date;
- evidence of interconnection;
- evidence of site control; and
- bidder's credit information.

As noted in the LEI First Status report, PacifiCorp's minimum criteria were reasonable and consistent with other renewable resource RFPs.[7] LEI observed that the bids which were disqualified were disqualified based on important and non-trivial criteria:

- ***COD after 2020:*** Failure to demonstrate a commercial online date prior to December 31, 2020 (17 bids disqualified);
- ***Lack of prospect of timely interconnection:*** Failure to provide evidence that the proposed project had a signed interconnection request with PacifiCorp transmission to execute an interconnection feasibility study agreement (15 bids disqualified); and
- ***Lack of site control:*** Failure to provide documentation of site control (3 bids disqualified).

Any bid which was not disqualified was then eligible for the ISL, and PacifiCorp evaluated these bids based on its ISL methodology.

After the bids were evaluated to assess their conformance with the minimum requirements, PacifiCorp's bid evaluation and selection process occurred in two phases:

[7] London Economics International LLC. "First Status Report - LEI - PacifiCorp Solar RFP 2017." January 10, 2018.

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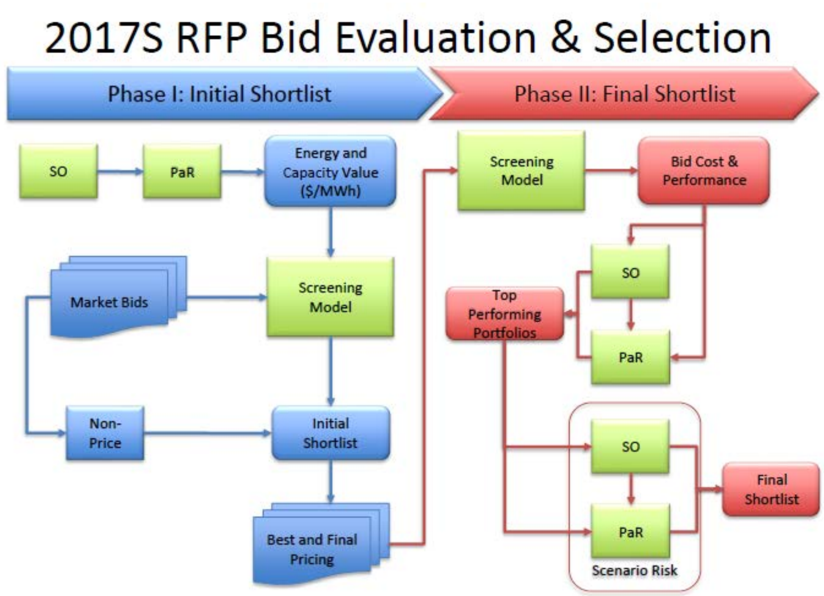
- ***Phase I:*** PacifiCorp established and ranked an ISL based on both price and non-price factors. Price accounted for 80% of the score and non-price factors for 20% (or a maximum of 20 points). Bids with the highest total score (price and non-price), representing up to 2,000 MW of aggregate capacity at any given location, were considered for the ISL. Bids selected for the ISL were then given an opportunity to provide best and final pricing;
- ***Phase II:*** PacifiCorp established its FSL based on an analysis of net customer benefit of the ISL bids with updated pricing. This net benefits analysis simulated PacifiCorp's system costs with and without ISL bids and compared the two outcomes to quantify the net benefits of the bids. In this phase, PacifiCorp calculated the expected net present value revenue requirement impacts of proposed solar projects.

PacifiCorp used its proprietary model (Screening model) and two models licensed from third parties (the SO model, and the PaR model), all discussed below, to perform quantitative analysis and rank the bids to create both the ISL and the FSL (see Figure 1). The method used to evaluate and select bids was consistent with the methods that were used in the IRP.[8]

Figure 1. PacifiCorp models used in ISL and FSL evaluation



Source: PacifiCorp 2017S Solar Request for Proposals, Bidders' Conference, November 21, 2017.

[8] PacifiCorp. "RFP 2017S Solar RFP Main Document." Pages 18 and 19. November 15, 2017. <http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2017S_RFP/Main_Documents/RFP_2017S_SOLAR_RFP_MAIN_DOCUMENT.pdf>.

3.2 Cost and benefit evaluation models

The primary model used for the ISL was the Screening Model, an excel-based model that calculates the net present value ("NPV") of the net benefits of each bid. PacifiCorp provided LEI with copies of the Screening Model for each bid which was included in the ISL.

3.2.1 Screening model

PacifiCorp's Screening model uses system-wide energy and capacity costs as inputs. These energy and capacity costs are estimated outside of the Screening model, by PacifiCorp's System Optimizer Model ("SO") and its Planning and Risk model ("PaR")[9]. In terms of their use to support the Screening models for the ISL:

- ***SO model:*** This model is run twice, to calculate system-wide energy and capacity costs with, and without, a proxy generic solar resource of 100 MW. The cost of this resource is assumed to be zero, in order that the SO model run with the capacity resource will be sure to include it. Thus, the difference in system costs on a $/MWh basis resulting from the two model runs reflects the benefit of having the solar resource on the system.
- ***PaR:*** This model is also run twice. The outputs of the SO models (energy and capacity costs) are fed into the PaR; the PaR creates 50 Monte Carlo simulations based on stochastic characteristics of natural gas prices, power prices, load, hydropower availability, and thermal outages. This is performed for the SO output which includes the proxy solar resource, and the SO output which does not.

The risked values (the average energy and capacity prices from the PaR model runs with and without the generic solar resource) are then incorporated into the Screening Model. These provide the Screening model with the estimated benefits of a generic solar resource, on a $/MWh basis for energy and capacity. These avoided costs of energy and capacity ("ACC") are the quantified benefits of a generic solar resource.

With the inputs derived from the SO and PaR models, the Screening model calculates the cost of a single bid and compares the cost to the ACC. It does this by calculating the real levelized (discounted) revenue requirement cost and the real levelized (discounted) benefit for each bid, where revenue requirement costs are reported as a negative value and customer benefits are reported as a positive value.[10] The Screening model is applied to each bid, separately.

The Screening model allows for different ACC values for each of five different market zones (Idaho, Oregon, Utah, Washington and Wyoming) (see Figure 2). This allows the avoided energy

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[9] These models are the same models used by PacifiCorp to develop resource portfolios in the 2017 IRP. Source: PacifiCorp. "2017 Integrated Resource Plan." Volume 1. April 14, 2017. These two models are discussed in more detail in Section 5 in the context of the FSL.

[10] PacifiCorp includes terminal value in the nominal levelized delivered benefit, however, it does not impact the model as the terminal value is zero (terminal value equals the residual value of assets minus decommissioning cost).

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and supply costs to vary across the market zones. An offer for a project located in a market zone with a higher avoided cost such as Washington would provide a greater benefit (higher avoided cost) than a project in a market zone such as Utah with low avoided costs, all else equal. LEI found this to be a reasonable approach.

Figure 2. PacifiCorp average ACC (NPV) by state

[redacted]

Source: Screening model version dated December 12, 2017

PacifiCorp used the results of the Screening model (the benefits and costs) to create a net cost calculation (in $/MWh) to score each bid individually. PacifiCorp created two different scoring methods:

- ***Scoring Method I:*** Net Cost/(Benefit) ["NC/(B)"] = Net Cost –Benefit
  - Scores were scaled so that the lowest NC/(B) was awarded 80 points, and the highest NC/(B) was awarded 0 points.
  - Bidder Score$_{x}$ = [NC/(B)$_{Highest}$ – NC/(B)$_{Bidderx}$) - (NC/(B)$_{Highest}$–NC/(B)$_{Lowest}$] x 80 Points
- ***Scoring Method II:*** Net Cost/Benefit ["NC/B"] = Net Cost / Benefit
  - Scores were scaled so that the lowest NC/B was awarded 80 points, and the highest NC/B was awarded 0 points.
  - Bidder Score$_{x}$ = [NC/B$_{Highest}$–NC/B$_{Bidderx}$) / (NC/B$_{Highest}$–NC/B$_{Lowest}$] x 80 Points

If the two methods resulted in different initial shortlists, PacifiCorp included bids supported by either method in its ISL.

LEI believes that this is a reasonable approach. Scoring Method I favors bids in which the absolute size of the benefit less the cost is largest (the "impact" of the bid); Scoring Method II favors bids which have the most attractive ratio of benefits to costs (the "efficiency") of the bid. By including bids that are acceptable under either methodology, PacifiCorp is including both impactful and efficient bids.

3.3 Non-price evaluation

The total non-price score accounts for up to 20% of the total bid score in ISL. It incorporates the relative development, construction and operational characteristics, and associated risks of each bid (see Figure 3).

Figure 3. PacifiCorp's non-price weighting factors

Non-Price Factor	Non-Price Factor Weighting
Conformity to RFP Requirements: • Bids provided all required RFP information pursuant to RFP instructions and schedule, including the accuracy of such information. • Bids provided complete and accurate required RFP information of but not limited to documentation of site control and permitting process, environmental compliance plan, and interconnection or transmission arrangements. • Bidder's development and construction experience related to large scale solar projects.	6%
Project Deliverability: • Bids demonstrated the commercial operation date would be achieved by December 31, 2020. • Bids provided sufficient detail, including schedule(s) and documentation, to demonstrate the ability of meeting all of the project's site control, environmental compliance, permits, and equipment procurement. • Bids demonstrate and provide sufficient detail regarding access to generation equipment and well defined O&M plan and financing plan. • Bids included documentation that projects qualify for and would receive the full or partial value of the federal ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service at commercial operation.	6%
Transmission Progression: • Bids provided sufficient detail, including schedule(s) and documentation for completing project interconnection and securing any required third party transmission service to support December 31, 2020 commercial operation date.	8%

Source: PacifiCorp 2017S RFP Bidders' Conference November 21, 2017

LEI believes that the 20% weighting is reasonable, as mentioned in the IE ISL Report.[11] Non-price scores were not taken into consideration in the FSL.

[11] London Economics International LLC. "Independent evaluator's report on initial shortlist selection process: PacifiCorp's 2017S RFP." January 26, 2018.

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4 PacifiCorp's ISL results

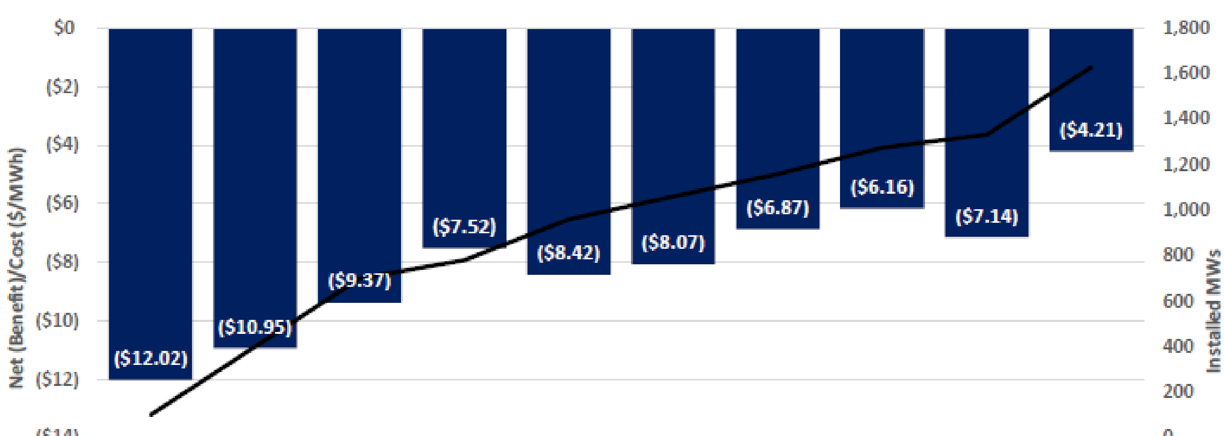
PacifiCorp 2017S RFP had a robust level of response, with over 100 bids offered. After disqualifying bidders which did not meet the minimum criteria, PacifiCorp followed the price and non-price ranking methodology described above and selected an ISL of 25 bids, covering 11 projects, with an aggregate solar capacity of 1,530 MW.

4.1 ISL selection

The two different price scoring methods described in Section 3 selected the same bid resources (albeit with a slightly different ranking between the bids). This means that the ISL was supported by both price scoring methodologies. Details on the bids and PacifiCorp's rankings are provided in Section 7 (Appendix A).

The ISL included projects with positive net benefits (negative costs) ranging between about $12/MWh and $4/MWh (see Figure 4). The ISL allowed up to approximately 2,000 MW of aggregate solar capacity, but at about $4/MWh of net benefit PacifiCorp saw a breakpoint and decided to close the ISL.

Figure 4. Net benefits of PacifiCorp ISL bids



[redacted]

Source: PacifiCorp 2017S RFP Initial Shortlist. January 8, 2018.
* Cove Mountain Expansion includes the Cove Mountain project (58 MW)

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4.2 LEI's assessment of the ISL

As noted in Section 2, LEI's task was to evaluate the RFP process, not the ISL or the individual bids themselves. However, so that LEI could be confident that our analysis was independent as well as comprehensive, LEI's methodology did not begin with PacifiCorp's ISL, and then work backward through PacifiCorp's process. Instead, LEI began by using limited but common-sense criteria for evaluation of the bids, to arrive at LEI's own "indicative" initial shortlist. The limited criterion LEI used was solely the levelized cost of the bid price for the PPA term. LEI refers to its initial shortlist as "indicative" because LEI did not analyze the bids based on a cost-benefit analysis or based on their geographic value.

PacifiCorp provided LEI with all the bid responses, including all documents and attachments. From this material, LEI created its indicative ISL. LEI then compared its indicative ISL to PacifiCorp's ISL.

LEI's indicative ISL was consistent with PacifiCorp's ISL, with the exception of bids in zones with high energy prices: [redacted] in Washington, and [redacted] in Oregon (see Figure 5).

Figure 5. Comparison between LEI indicative ISL and PacifiCorp ISL

Bid Resource	State	LEI Rank	PacifiCorp Rank
[redacted]	WA	not selected	1
	UT	1	3
	UT	4	2
	UT	3	6
	UT	7	4
	UT	6	9
	UT	2	5
	UT	8	10
	OR	not selected	8
	UT	9	7
	UT	5	11

LEI's indicative ISL provided an unbiased guide to what the PacifiCorp ISL might look like. LEI would not expect 100% overlap, but bids that did not make LEI's ISL point to the importance of

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PacifiCorp's criteria other than price, in creating the PacifiCorp ISL. PacifiCorp's Screening model calculated the net benefit for each bid based on the resource location. Washington has the highest ACC value, followed by Oregon, allowing bids located in those states to have a higher net customer benefits, even with higher bid prices (see Figure 6). Capitas High Top Solar was the only bid resource offered in Washington, and Invenergy Prineville and Millican Solar Energy Center was the cheapest bid offered in Oregon. Resources were offered in Wyoming, but prices were not competitive. No resources were offered in Idaho.

LEI found the PacifiCorp ISL process to be fair, unbiased and reasonable, and the outcome represented the best value to customers given the Phase (I) of the evaluation process.

Figure 6. ACC Value of Energy and Capacity (NPV 2018-2042) vs ISL PPA prices

State	Indicative ACC	Minimum PPA price	Maximum PPA price
Idaho	[redacted]	n/a	
Oregon	[redacted]	[redacted]	[redacted]
Utah	[redacted]	[redacted]	[redacted]
Washington	[redacted]	[redacted]	[redacted]
Wyoming	[redacted]	not shortlisted	

Sources:
ACC = Excel spreadsheet "2017S RFP Solar Energy and Capacity Benefits.xlsx" version dated December 12, 2017
PPA prices = Bid submission (first-year PPA price)

5 PacifiCorp's FSL results

LEI believes the FSL results represent an unbiased evaluation that reflects the process described to the bidders in the bid documents. PacifiCorp made reasonable assumptions for key value drivers such as future natural gas and carbon prices. PacifiCorp used appropriately sophisticated modeling tools.

5.1 Best and final bids

As mentioned earlier, PacifiCorp gave bids selected to the ISL the opportunity to provide best and final pricing for the FSL evaluation process. PacifiCorp received best and final pricing on February 1, 2018. Best and final pricing had to meet two requirements:

- provide same site using the same or similar project equipment as original proposal, and
- not exceed 10% of the original total bid cost (assess on a nominal levelized present value revenue requirement basis).

If best and final pricing increased the total bid cost by more than 10%, PacifiCorp could either reject the best and final proposal or replace the short-listed bid with another bid not originally selected to the ISL.

The majority of the bidders selected to the ISL maintained their original bid price, with the exception of [redacted], who decreased their initial bid price between 1% and 3%, and [redacted], who increased their initial bid price by 5% (see Figure 7).

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Figure 7. ISL and best and final pricing comparison

Bidder Name	Project/Alternative	ISL		B&F	
		PPA price (1st year)	PPA price annual growth	PPA price (1st year)	PPA price change (%)
[redacted]					

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

5.2 PacifiCorp's FSL evaluation process

The following section outlines PacifiCorp's FSL evaluation process. LEI reviewed PacifiCorp's evaluation process in detail: PacifiCorp presented the methodology of the SO and PaR models and LEI asked detailed questions related to them;[12] and LEI reviewed PacifiCorp's key input assumptions. LEI did not acquire copies of the SO and PaR models. LEI believes the process was conducted fairly and was consistent with the process outlined in the RFP documents, assumptions used in the models were reasonable, and the quantitative analysis was consistent with industry best practices.

PacifiCorp used the same models for the FSL price evaluation as it used in the ISL process. The best and final pricing was put into the Screening model to produce the cost and performance data which the SO and PaR models require. These production cost models were then used to perform a net customer benefit analysis by simulating PacifiCorp's system costs with and without the ISL bids under nine baseline scenarios. Both SO model and PaR simulations were run over a 20-year planning horizon (2017-2036), which aligns with the planning horizon used in the 2017 IRP.

[12] Conference call, PacifiCorp and LEI, March 2, 2018.

In the ISL process, each bid was tested individually and in a single scenario; whereas, in the FSL process, the bids as a group were tested across nine scenarios (based on combinations of natural gas prices and CO_2 prices). PacifiCorp then selected the solar resource portfolio composed of the bid resources that were most consistently selected among the nine scenarios, for stochastic analysis using the PaR model. This process was explained to bidders, in the document provided for the bidders' conference.

In addition, PacifiCorp ran two sensitivities (discussed in more detail below). This process was not explicitly documented for the bidders, but was not inconsistent with the RFP guidelines and, in LEI's view, was applied fairly.

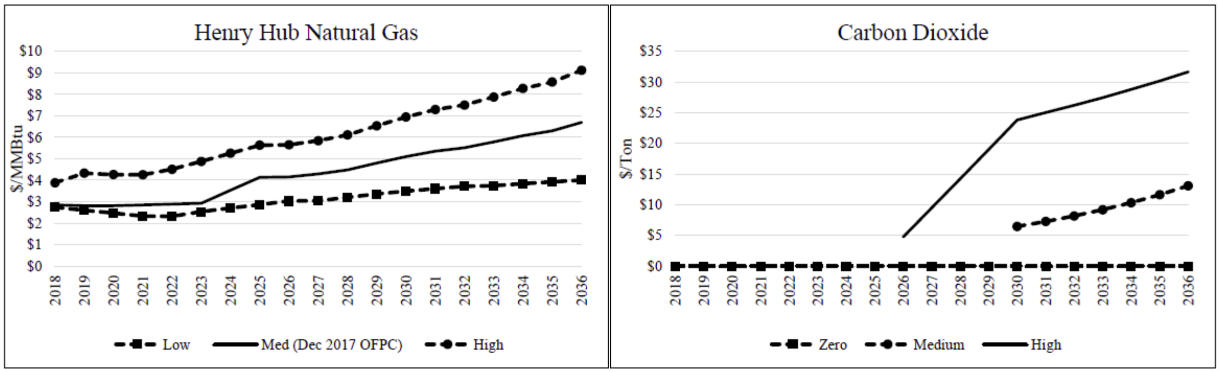
5.2.1 Defining baseline scenario assumptions

Based on three different outlooks for natural gas prices, and three different outlooks for CO_2 prices, PacifiCorp developed nine scenarios (referred to by PacifiCorp as "price-policy" scenario assumptions). These are conceptually consistent with those used in the 2017 IRP, but updated to reflect PacifiCorp's assessment of the most current information.[13] These baseline scenarios were defined by assumptions of low, medium, and high alternatives for natural gas and CO_2 pricing (see Figure 8). The natural gas outlooks were based on the forward market for 72 months (in the medium case), and after that, on forecasts developed by third-parties. PacifiCorp noted that the increase in the gas price outlook from 2023 to 2025 was based on assumptions about rising liquefied natural gas ("LNG") exports. The CO_2 price outlooks were based on forecasts developed by third parties.

Given the characteristic uncertainty over the future of natural gas prices and CO_2 policy, LEI believes that conducting a scenario-based analysis was reasonable and prudent. Scenario analysis helps ensure that decisions are robust across a range of future outcomes; and use of scenarios reflects industry best practices for long-term strategic planning and investment.

[13] PacifiCorp. "RFP 2017S Solar RFP Main Document." Page 23, footnote 9. November 15, 2017. <http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2017S_RFP/Main_Documents/RFP_2017S_SOLAR_RFP_MAIN_DOCUMENT.pdf>

Figure 8. PacifiCorp's price-policy scenarios



Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

5.2.2 SO model created portfolios of cost-effective solar bids for the nine baseline scenarios

PacifiCorp ran the SO model with the complete ISL (and all other assumed available resources) for each of the nine scenarios. The model selected new solar capacity at any level that reduced system costs, and it could select all, some, or none of the bids.

The group of bids selected was referred to by PacifiCorp as the "resource portfolio." Each of the nine scenarios produced its own resource portfolio of cost-effective bids, though many bids appeared in nearly all the portfolios (see Figure 9). Five bids were selected in all nine scenarios, one bid was selected in eight scenarios, and two bids were selected in four scenarios.

Then PacifiCorp ran the SO model nine more times, once for each scenario, and in each case, without the portfolio of selected bids. This provided a baseline (or, rather, nine different baselines) against which to test the impact on the present value revenue requirement ("PVRR") (including all relevant transmission interconnection costs) of the solar resource portfolio, in each scenario. The results of comparing each baseline scenario with and without the resource portfolio is shown in the row labelled "SO Model PVRR (difference) (Benefit)/cost ($m)" in Figure 9.

5.2.3 PaR model examines risk profile of portfolios

In the next step, PacifiCorp used the PaR model to analyze the risk of each resource portfolio developed with the SO model. PaR captures stochastic risk in its production cost estimates, without altering the resource portfolio, by using Monte Carlo sampling of the following stochastic variables: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The PaR model calculated the stochastic mean and the risk-adjusted present value revenue requirement differential with and without the bid portfolio for each scenario. PacifiCorp was interested in two metrics:

- ***Stochastic mean metric:*** the average of system net variable operating costs for 50 iterations, combined with the real levelized capital costs and fixed costs taken from the SO model;

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- ***Risk-adjusted metric:*** adds 5% of system variable costs from the 95th percentile to the stochastic mean. The risk-adjusted metric incorporates the expected value of low-probability, high-cost outcomes.

Figure 9. Nine bid portfolios selected by SO baseline model

Bid	1 Low Gas Zero CO_2	2 Low Gas Med CO_2	3 Low Gas High CO_2	4 Med Gas Zero CO_2	5 Med Gas Med CO_2	6 Med Gas High CO_2	7 High Gas Zero CO_2	8 High Gas Med CO_2	9 High Gas High CO_2
[redacted]	n/s	n/s	n/s	n/s	n/s	✓	✓	✓	✓
[redacted]	✓	✓	✓	✓	✓	✓	✓	✓	✓
[redacted]	✓	✓	✓	✓	✓	✓	✓	✓	✓
[redacted]	✓	✓	✓	✓	✓	✓	✓	✓	✓
[redacted]	n/s	✓	✓	✓	✓	✓	✓	✓	✓
[redacted]	✓	✓	✓	✓	✓	✓	✓	✓	✓
[redacted]	✓	✓	✓	✓	✓	✓	✓	✓	✓
[redacted]	n/s	n/s	n/s	n/s	n/s	✓	✓	✓	✓
[redacted]	✓	✓	n/s	n/s	n/s	n/s	n/s	n/s	n/s
[redacted]	n/s	n/s	✓	✓	✓	✓	✓	✓	✓
Total Capacity	1,042 MW	1,122 MW	1,320 MW	1,320 MW	1,320 MW	1,535 MW	1,535 MW	1,535 MW	1,535 MW
SO Model PVRR(difference) (Benefit)/Cost ($m)	($127)	($155)	($250)	($227)	($247)	($385)	($520)	($529)	($559)
PaR Stochastic-Mean PVRR(difference) (Benefit)/Cost ($m)	($79)	($106)	($188)	($135)	($174)	($303)	($338)	($348)	($501)
PaR Risk-Adjustedn PVRR(difference) (Benefit)/Cost ($m)	($83)	($112)	($197)	($141)	($183)	($318)	($354)	($365)	($525)

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

The results of comparing the risked baseline to the resource set with the bids are shown in row "PaR Model Stochastic-Mean PVRR (difference) (Benefit)/cost ($m)" and in row "PaR Model Risk-Adjusted PVRR (difference) (Benefit)/cost ($m)" in Figure 9.

LEI believes adding a risk-adjusted component to the analysis, as PacifiCorp did using the PaR model, was reasonable and prudent, as it provided additional insight into the potential value of a solar resource portfolio.

5.3 PacifiCorp chose two portfolios for further testing

PacifiCorp chose the bid resources consistently selected among the nine scenarios and created two 2017S RFP solar resource portfolios (see Figure 10). Bid portfolio 1 contained all the bids SO selected in any scenario; Bid Portfolio 2 contained only the bids that SO selected in all the scenarios.

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Figure 10. Selected portfolios

Bid Portfolio 1	Bid Portfolio 2
[redacted]	[redacted]
Total Capacity = 1,535 MW	**Total Capacity = 1,320 MW**

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

These top-performing bid portfolios were further analyzed in the scenario risk analysis phase of the FSL bid evaluation process.

5.4 Baseline scenario risk analysis of the top two portfolios

This step of the evaluation process identified whether the two top-performing portfolios would experience poor performance under any of the scenarios. The two bid portfolios were analyzed under all nine scenarios, using the SO and PaR models.[14]

First, in the SO model, PacifiCorp calculated the present value revenue-requirement differential between two model runs – one with and one without the solar PPAs – for each scenario. The SO model results showed greater benefits from Bid Portfolio 2 compared to Bid Portfolio 1 in five out of the nine scenarios: all the low gas scenarios, the medium gas/zero CO_2 price scenario, and the medium gas/medium CO_2 price scenario (see Figure 11).

[14] All simulations included PacifiCorp's new wind and transmission investments.

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Figure 11. Baseline scenario risk analysis results: SO model (million dollars)

Price-Policy Scenario	Bid Portfolio 1 (Benefit)/Cost	Bid Portfolio 2 (Benefit)/Cost	Difference
Low Gas, Zero CO_2	($80)	($115)	($36)
Low Gas, Medium CO_2	($118)	($148)	($30)
Low Gas, High CO_2	($232)	($250)	($18)
Medium Gas, Zero CO_2	($216)	($227)	($11)
Medium Gas, Medium CO_2	($240)	($247)	($8)
Medium Gas, High CO_2	($385)	($370)	$15
High Gas, Zero CO_2	($520)	($483)	$37
High Gas, MediumCO_2	($529)	($493)	$35
High Gas, High CO_2	($559)	($517)	$43

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

To determine how system operations might impact the value of the portfolios, PacifiCorp analyzed the stochastic-mean and risk-adjusted PaR results for each scenario (see Figure 12 and Figure 13).

Figure 12. Baseline scenario risk analysis results: Stochastic-mean PaR (million dollars)

Price-Policy Scenario	Bid Portfolio 1 (Benefit)/Cost	Bid Portfolio 2 (Benefit)/Cost	Difference
Low Gas, Zero CO_2	($1)	($45)	($44)
Low Gas, Medium CO_2	($43)	($84)	($41)
Low Gas, High CO_2	($159)	($188)	($29)
Medium Gas, Zero CO_2	($110)	($135)	($25)
Medium Gas, Medium CO_2	($142)	($174)	($31)
Medium Gas, High CO_2	($303)	($294)	$9
High Gas, Zero CO_2	($338)	($320)	$19
High Gas, MediumCO_2	($348)	($329)	$19
High Gas, High CO_2	($501)	($473)	$28

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

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Figure 13. Scenario risk analysis results: risk-adjusted PaR (million dollars)

Price-Policy Scenario	Bid Portfolio 1 (Benefit)/Cost	Bid Portfolio 2 (Benefit)/Cost	Difference
Low Gas, Zero CO_2	($2)	($48)	($46)
Low Gas, Medium CO_2	($46)	($89)	($43)
Low Gas, High CO_2	($168)	($197)	($29)
Medium Gas, Zero CO_2	($115)	($141)	($26)
Medium Gas, Medium CO_2	($150)	($183)	($33)
Medium Gas, High CO_2	($318)	($309)	$9
High Gas, Zero CO_2	($354)	($335)	$20
High Gas, MediumCO_2	($365)	($345)	$20
High Gas, High CO_2	($525)	($511)	$13

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

Bid Portfolio 2 (the smaller portfolio) relative to Bid Portfolio 1 had greater benefits both in the stochastic-mean PaR and the risk-adjusted PaR results. Based on the SO model and PaR results, PacifiCorp identified Bid Portfolio 2 as preferable to Bid Portfolio 1.

5.5 Additional sensitivity analyses

PacifiCorp informed LEI of its intention to run additional sensitivity analyses in a March 2, 2018 conference call with LEI. In addition, PacifiCorp had informed bidders that it may take into consideration other factors that are not expressed in the RFP document when deciding the final shortlist.[15] PacifiCorp ultimately ran two additional sensitivity analyses: 1) hourly price profiles, and 2) capacity contribution sensitivities. PacifiCorp performed these sensitivity analyses on Bid Portfolio 2 for two of the baseline scenarios: medium gas/medium CO_2 and low gas/zero CO_2.

5.5.1 Hourly price profile sensitivity

For the baseline analysis described above, PacifiCorp used average hourly price profiles derived from historical Powerdex data (five years of on peak and off-peak data). The hourly market price profiles vary by month and day type (weekdays, Saturdays, and Sundays/holidays). However, PacifiCorp was concerned that this hourly profile would not reflect system conditions in the future, when the Western Electricity Coordinating Council ("WECC") region is projected to have more solar in its system.

[15] PacifiCorp. "RFP 2017S Solar RFP Main Document." Page 24. November 15, 2017. <http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2017S_RFP/Main_Documents/RFP_2017S_SOLAR_RFP_MAIN_DOCUMENT.pdf>.

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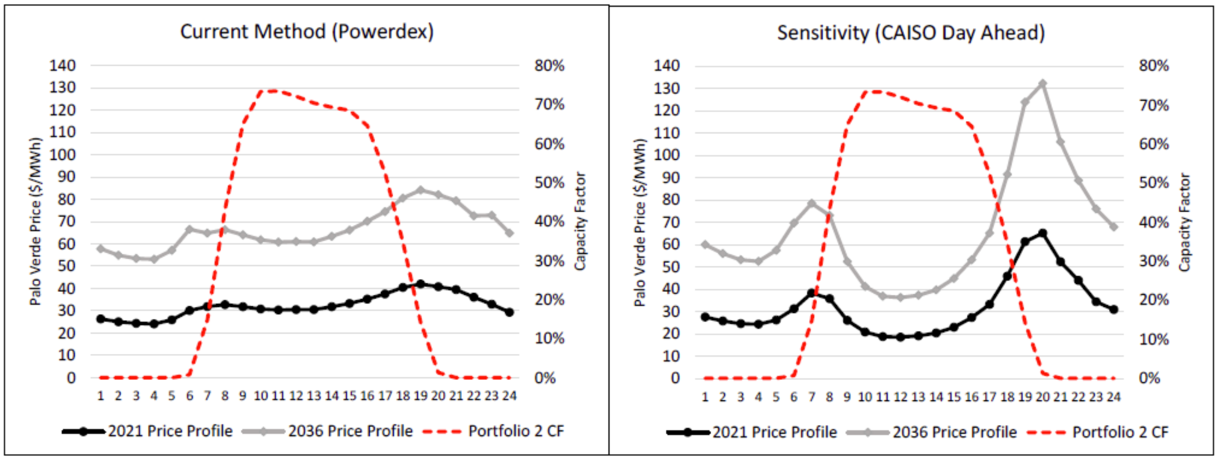
Therefore, PacifiCorp developed a sensitivity analysis based on an alternative set of prices derived from one year of day-ahead hourly prices available from the California Independent System Operator ("CAISO") (see Figure 14).

Figure 14. Hourly price profile sensitivity



Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

In both charts, the hourly price profile is based on the average hourly prices from representative months (January, April, July, and October) and shown alongside the average hourly capacity profile of bids included in Bid Portfolio 2. This shows that prices would be lower during those hours when the resources in Bid Portfolio 2 are expected to generate electricity.

PacifiCorp used the CAISO hourly prices to run a sensitivity with the PaR model. Results showed that the value of Bid Portfolio 2 was reduced by $66 million to $69 million in the medium gas/medium CO_2 scenario and by $55 million to $58 million in the low gas/zero CO_2 scenario. In the low gas/zero CO_2 scenario, Bid Portfolio 2 shifted from showing net benefits to showing a net cost when the CAISO hourly price profile was assumed (see Figure 15). Net benefits remained positive in the medium gas price/medium CO_2 price scenario.

Figure 15. Hourly price-profile sensitivity results (million dollars)

Price-Policy Scenario/ PaR	Medium Gas, Medium CO_2		Low Gas, Zero CO_2	
	Stochastic-Mean PaR (Benefit)/Cost	Risk-Adjusted PaR (Benefit)/Cost	Stochastic-Mean PaR (Benefit)/Cost	Risk-Adjusted PaR (Benefit)/Cost
Benchmark Case (Current Price Profile)	($174)	($183)	($45)	($48)
Hourly Price-Profile Sensitivity	($108)	($114)	$10	$10
Decreased Net Benefit	**$66**	**$69**	**$55**	**$58**

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

PacifiCorp pointed to trends which may impact price profiles even further, and compiled the following findings:[16]

- S&P Global Market Intelligence reported solar capacity in the WECC region is expected to grow by 77% in six years, from 16.8 GW in 2017 to 29.8 GW by 2023.
- The Energy Information Administration's Annual Energy Outlook 2018 ("AEO 2018") Reference Case also shows continued growth trends of solar capacity in the WECC, reaching 46.8 GW by 2050.

Thus, PacifiCorp believes that the rapid increase in solar capacity across the WECC region over the past five years has significantly impacted hourly market prices and continued solar capacity growth could further affect the market value of solar energy even beyond the results of the price profile sensitivity.

It is LEI's view that PacifiCorp's alternative price profile was a reasonable way to examine potential downside risks to customers of committing to solar resources. PacifiCorp also informed LEI that it will be evaluating the hourly price profile it will use in the next IRP.[17]

5.5.2 Capacity contribution sensitivity

PacifiCorp's SO and PaR modeling relied on the capacity contribution value developed for the 2017 IRP, which was 59.7% for solar resources. In other words, FSL evaluation assumed that the solar resources in Bid Portfolio 2 can displace the need for approximately 788 MW of system capacity (59.7 percent x 1,320 MW).

PacifiCorp believes that as more highly correlated solar generation is added to the system, the energy output from these resources will shift the timing of potential loss-of-load events to evening hours when solar irradiance is low and generation levels are greatly reduced or zero.[18] Consequently, solar capacity contribution values would decline with increasing solar penetration levels (see Figure 16). PacifiCorp informed LEI that the addition of 1,320 MW of solar capacity would increase the percentage of solar on PacifiCorp's system from 5% to 10%.

[16] PacifiCorp 2017S Request for Proposals Final Shortlist. Page 14. March 12, 2018.

[17] Conference call LEI and PacifiCorp, March 19, 2018

[18] PacifiCorp 2017S Request for Proposals Final Shortlist. Page 15. March 12, 2018.

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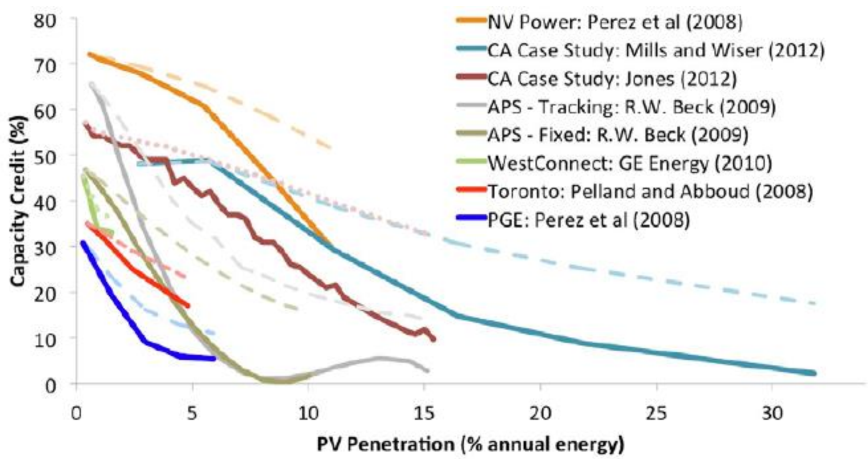
Figure 16. Capacity contribution of solar resources represented as a percentage of resource



Source: Mills, Andrew, and Ryan Wiser. 2012. "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes." LBNL-5933E, Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory.

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

Therefore, PacifiCorp ran a sensitivity based on halving the capacity contribution value from 59.7% to 29.9%. This would reduce the amount of system capacity that the Bid Portfolio 2 can displace from 788 MW to 394 MW. This reduced the resource-deferral value of the resources in Bid Portfolio 2, therefore reducing the net benefits of the solar PPA bids (see Figure **17**).

Figure 17**. Capacity contribution sensitivity results (million dollars)**

Price-Policy Scenario/ PaR	Medium Gas, Medium CO_2		Low Gas, Zero CO_2	
	Stochastic-Mean PaR (Benefit)/Cost	Risk-Adjusted PaR (Benefit)/Cost	Stochastic-Mean PaR (Benefit)/Cost	Risk-Adjusted PaR (Benefit)/Cost
Benchmark Case (Current Price Profile)	($174)	($183)	($45)	($48)
Capacity-Contribution/Hourly Price Profile Sensitivity	($69)	($73)	$56	$58
Decreased Net Benefit	**$105**	**$110**	**$101**	**$106**

Source: PacifiCorp 2017S Request for Proposals Final Shortlist. March 12, 2018

The combined effect of the hourly price-profile and capacity-contribution assumptions was to reduce the net benefits by approximately $105 million to $110 million in the medium gas/medium CO_2 scenario and by approximately $101 million to $106 million in the low gas/zero CO_2 scenario.

In LEI's view, the halving of the solar capacity value provides a hypothetical downside sensitivity, but one that may not be easy to defend empirically. As Figure 16 above shows, the relationship between solar capacity and penetration varies widely; and the data referred to in that figure may be out of date, as the reports cited date from 2008-2012.

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5.6 PacifiCorp's FSL final recommendation: No winners

The bid selection process identified two potential bid portfolios as candidates for the 2017S RFP final shortlist, and the baseline scenario risk analysis phase showed that Bid Portfolio 2 was preferable. However, while analysis (excluding the sensitivity cases) shows that there would be potential customer net benefits, PacifiCorp decided not to award any bids:

- **PacifiCorp noted that its sensitivity analyses showed that there is a risk that projected benefits are overstated**.[19] This refers to the hourly price profile sensitivity analysis and the capacity contribution sensitivity analysis.
- **PacifiCorp felt that bidders' offer prices incorporated a risk premium**. PacifiCorp believes the 2017S RFP bid prices incorporated potential tax reform and tariff-related uncertainties, which were part of the market environment in late 2017 and early 2018. PacifiCorp believes, if a new RFP were to be issued in 2018, it would attract bids for solar projects that could still come online by 2021 (and qualify for the 30 percent ITC), at lower prices. The lower-priced bids would reflect reductions in the cost of solar equipment and avoid the risk premium that was driven by tariff and tax reform uncertainties.
- **PacifiCorp felt that more projects could be viable in the near future.** PacifiCorp also pointed to the possibility that a future RFP would allow time participants to be further along with permitting, site control, or the transmission interconnection process.[20]
- **PacifiCorp noted a future solicitation could include storage.** With more lead time, a new solicitation could include storage with solar, which could help mitigate valuation risks.[21]

For wind procurement, PacifiCorp had to move quickly to attract projects which could be under way in time to get the full Production Tax Credit ("PTC"). The ITC has more time, as it ramps down from 30% to 26% in 2020, 22% in 2021, and finally to 10% in 2022.[22] In the coming months, PacifiCorp surmises that bid prices for PPAs could fall, owing to improvements in technology, or to greater perceived certainty over tax and tariff rules. The solar panel tariff, issued on January 22, 2018, increased tariffs on imported solar cells and modules by 30% for the first year, and will fall by 5% annually, dropping to a 15% tariff in 2021.[23] Thus, by 2021 PacifiCorp may be correct to assume cell and module prices will be lower.

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[19] PacifiCorp 2017S Request for Proposals Final Shortlist. Page 2. March 12, 2018.

[20] PacifiCorp 2017S Request for Proposals Final Shortlist. Page 2. March 12, 2018.

[21] PacifiCorp 2017S Request for Proposals Final Shortlist. Page 2. March 12, 2018.

[22] U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). <https://www.energy.gov/savings/business-energy-investment-tax-credit-itc>

[23] Office of the United States Trade Representative. "Section 201 Cases: Imported Large Residential Washing Machines and Imported Solar Cells and Modules." January 22, 2018. <https://ustr.gov/sites/default/files/files/Press/fs/201%20Cases%20Fact%20Sheet.pdf>

6 Conclusion: 2017S RFP was conducted fairly and in accordance with industry best practices

PacifiCorp's 2017S RFP was conducted at the recommendation from the Utah Public Service Commission—it was not a requirement.[24] LEI's involvement as the IE was, again, at the option of PacifiCorp, as an IE was not required. These two conditions point to a disposition on the part of PacifiCorp to conduct business in a transparent and open manner.

To summarize LEI's finding in this report, LEI believes the 2017S RFP procurement process was fair and unbiased:

- The 2017S RFP documents were clear and available to all bidders;
- The minimum eligibility requirements were reasonable and applied consistently among bids, eliminating bids unable to demonstrate ability to meet the commercial online date
- The screening factors in the ISL were applied consistently among bids;
- The evaluation was performed consistently among bids and with Commission-approved bidding guidelines;
- All bids selected in to the ISL were given the opportunity to provide best and final pricing for the FSL evaluation process;
- The FSL evaluation process was conducted according to the processes outlined in the RFP;
- All ISL Screening models were provided to the LEI to check inputs, outputs, and results;
- The SO and PaR models were explained to LEI thoroughly and in-depth;
- There were no confidentiality claims or concerns between IE and PacifiCorp during the solicitation process.

LEI finds that the PacifiCorp's FSL evaluation process was conducted in alignment with the guidelines established in the 2017S RFP main document. PacifiCorp was explicit in reserving the right to reject all bids in its sole discretion.[25] In addition, PacifiCorp relied on best practices such

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[24] The Utah PSC order recommending the solar RFP aligned with the Wind RPF COD was issued on September 22, 2017. Docket 17-035-23. <https://pscdocs.utah.gov/electric/17docs/1703523/2969071703523oarfpwsm9-22-2017.pdf>

[25] PacifiCorp. "RFP 2017S Solar RFP Main Document." Page 10. November 15, 2017. <http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2017S_RFP/Main_Documents/RFP_2017S_SOLAR_RFP_MAIN_DOCUMENT.pdf>.

as examination of multiple scenarios for future net benefits, and stochastic tools for projecting the risks to these benefits.

6.1 Recommendations

LEI did not find PacifiCorp's decision not to accept any solar bids to be unreasonable or unfair. The circumstances around the RFP were unusual, in that the company did not have the opportunity to apply a full IRP process to the decision to offer a solar procurement.

However, the risk of not choosing any winning bidders is that future procurements may attract fewer bidders. PacifiCorp is in the process of developing its 2019 IRP, which may demonstrate that new solar resources provide economic benefits for customers. The new 2019 IRP will incorporate a thorough evaluation of hourly price profiles and capacity contribution risks.[26] PacifiCorp has said it expects the market environment for solar to improve over 2018, so that potential bidders in a future RFP can offer lower prices; it also cited the opportunity for solar bids to potentially incorporate storage; and allow more bidders to be further along in the process of permitting, site control, and transmission interconnection.

To ensure that bidders will come back to the table, LEI recommends that PacifiCorp explain clearly and to all bidders, and indeed to the broader solar development community, its rationale for not selecting any bids to the FSL, and underscore that the main issue was the timing rather than a fundamental concern about solar power. In addition, LEI recommends that PacifiCorp add to any future RFP documents that it reserves the right to stress test any final potential portfolios so that bidders are more aware of that potential evaluation process.

[26] PacifiCorp 2017S Request for Proposals Final Shortlist. Page 26. March 12, 2018.

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7 Appendix A: PacifiCorp Initial Shortlist Detailed Results

The initial shortlist consisted of 25 bids, based on over 11 projects with an aggregate solar capacity 1,530 MW (see Figure 18). The different prices for each project represent separate bids.

Figure 18. PacifiCorp ISL

Bid Resource	COD	Location	Capacity	NLDC[1] ($/MWh)	NLDB[2] ($/MWh)	Rank	Price Score[3] (%)	Non-price Score (%)
[redacted]	15-Dec-20	WA	100	[redacted]	[redacted]	1	80	14
[redacted]	1-Dec-20	UT	100-300	[redacted]	[redacted]	3	71	13
[redacted]	1-Dec-20	UT	100-300	[redacted]	[redacted]	2	77	13
[redacted]	31-Dec-20	UT	100	[redacted]	[redacted]	6	67	18
[redacted]	31-Dec-20	UT	80	[redacted]	[redacted]	4	65	19
[redacted]	31-Dec-20	UT	58	[redacted]	[redacted]	9	58	18
[redacted]	31-Dec-20	UT	122	[redacted]	[redacted]	5	68	15
[redacted]	31-Dec-20	UT	58	[redacted]	[redacted]	10	64	11
[redacted]	31-Dec-20	OR	115	[redacted]	[redacted]	8	61	17
[redacted]	30-Nov-20	UT	99	[redacted]	[redacted]	7	63	18
[redacted]	30-Nov-20	UT	198	[redacted]	[redacted]	11	54	17

1 NLDC = Nominal Levelized Delivered Cost.
2 NLDB = Nominal Levelized Delivered Benefit. The NLDB includes a terminal value of zero.
3 Price Score using method 1.

8 Appendix B: Role of the Solar Independent Evaluator

The following material is from PacifiCorp's Appendix M of the 2017S RFP.

1) The general role and function of the Independent Evaluator ("IE") are outlined as follows.

   The Independent Evaluator will facilitate and monitor communications between PacifiCorp and bidders.

   a. Review and validate the assumptions and evaluation calculations of any bids.

   b. Analyze and evaluate bids for reasonableness and consistency with the solicitation process.

   c. Access all important models in order to analyze, operate and validate all important models, modeling techniques, assumptions and inputs utilized by PacifiCorp in the solicitation process

   d. Receive copies of bid responses.

   e. Provide input to PacifiCorp on:

      i. the development of screening and evaluation criteria, ranking factors and evaluation methodologies that are reasonably designed to ensure that the solicitation process is fair, reasonable and in the public interest in preparing a solicitation and in evaluating the bids;

      ii. the development of initial screening and evaluation criteria that take into consideration the assumptions included in the PacifiCorp's most recent IRP, any recently filed IRP Update, any Commission order on the IRP or IRP Update;

      iii. whether a bidder has met the criteria specified in any bidding process and whether to reject or accept non-conforming bid responses;

      iv. whether and when data and information should be distributed to bidders when it is necessary to facilitate a fair and reasonable competitive bidding process or has been reasonably requested by bidders;

      v. whether to reject non-conforming bids for any reason or accept conforming changes;

      vi. whether to return bid fees.

   f. Ensure that all bids are treated in a fair and non-discriminatory manner.

   g. Monitor, observe, validate and offer feedback to PacifiCorp on all aspects of the solicitation and solicitation process, including:

i. evaluation and ranking of bid responses;

ii. creation of a short list(s) of bidders for more detailed analysis and negotiation;

iii. post-bid discussions and negotiations with, and evaluations of, shortlisted bidders, and negotiation of proposed contracts with successful bidders.

h. Once the competing bids have been evaluated by PacifiCorp and the IE, PacifiCorp and the IE will compare results.

i. Offer feedback to PacifiCorp on possible adjustments to the scope or nature of the solicitation or requested resources in light of bid responses received.

j. Solicit additional information on bids necessary for screening and evaluation purposes.

k. Analyze and attempt to mediate disputes that arise in the solicitation process with PacifiCorp and/or bidders

l. Coordinate as appropriate and as directed by PacifiCorp with staff or evaluators designated by regulatory authorities from other states served by PacifiCorp.

2) The communications between the IE, PacifiCorp, and the bidders shall be conducted in the following manner:

a. the IE will be included in the communications between the parties.

3) The IE shall prepare at least the following confidential reports and provide them to PacifiCorp:

a. Final reports as soon as possible following the completion of the solicitation process. Final reports shall include analyses of the solicitation, the solicitation process, the PacifiCorp's evaluation and selection of bids and resources, the final results and whether the selected resources are in the public interest.

REDACTED
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

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Surrebuttal Testimony of Joelle R. Steward

May 2018

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

A. Yes.

PURPOSE AND SUMMARY OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. In support of 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"), I respond to regulatory and ratemaking policy issues raised in the supplemental rebuttal and surrebuttal testimonies filed April 17, 2018, by Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Mr. Charles E. Peterson, and Mr. David Thomson, and Office of Consumer Services ("OCS") witnesses Mr. Bela Vastag, Mr. Philip Hayet, and Ms. Donna Ramas.

Q. Please summarize your testimony.

A. The Company's application for approval of the Resource Tracking Mechanism ("RTM") for interim recovery of the Combined Projects is the most reasonable approach to match the costs and benefits of the Combined Projects and provide the Company an opportunity to recover its prudently-incurred costs. Moreover, the alleged complexities of the RTM are minor compared to the alternative approaches, including deferrals and back-to-back rate cases to capture the full impact on revenue requirement.

Conditions on approval related to projected costs and benefits, proposed by several parties, are unnecessary, unprecedented, and unjustified. As previously noted in the Company's rebuttal testimony filed in January 2018, the Company has accepted the risks that are within the Company's control related to qualification for the production tax credits ("PTCs"). Additionally, both the Significant Energy Resource Approval law, Utah Code Ann. § 54-17-303 and -304, and Voluntary Request for Resource Decision Review law, Utah Code Ann. § 54-17-403 and -404, already provide substantial customer protections for potential changes in the projects that would occur during implementation, such as cost-overruns. Consistent with these laws, the Company's filing includes a soft cost cap based on the estimated costs of the Combined Projects for implementing the RTM. The Company will seek a prudence determination for any variances in excess of the current projected costs in the next rate case. If there is a major change in circumstances before construction, the Company will seek additional Commission guidance through the Order to Proceed process. Additional conditions for cost caps on capital or operations and maintenance are inconsistent with Utah's resource approval laws.

Finally, with the removal of the Uinta wind project from this application, the net rate impact for the Combined Projects' is now 1.4 percent for the first full year of operation.

RESOURCE TRACKING MECHANISM

Q. Have parties raised any new objections to the Company's proposed RTM?

A. No. For the most part, the positions and arguments raised by the parties in their supplemental rebuttal and surrebuttal testimonies reiterate positions and arguments already presented. Thus, my rebuttal testimony filed on January 16, 2018, largely addresses the issues raised in the April 17, 2018 surrebuttal testimony. I will, however, respond to further refinements to the arguments in the testimonies of Mr. Thomson and Ms. Ramas.

Q. **Both Mr. Thomson and Ms. Ramas dismiss the Company's concern that there is uncertainty about approval of a future test period if a general rate case is relied upon to begin recovery of the Combined Projects instead of the RTM. (Thomson Surrebuttal and Supplemental Rebuttal, lines 18–31; Ramas Second Rebuttal, lines 91–178.) Ms. Ramas represents this as "the Company's uncertainty of its ability to present adequate evidence supporting a future test year." Do you agree with her representation?**

A. No. The Company has presented substantial evidence to support future test periods in various general rate cases throughout the years and is confident it can continue to do so. Nonetheless, test period is typically a contested item in the Company's Utah rate cases. There is no guarantee that the Company will be able to use a future test period that captures the same matching of costs and benefits that the RTM would provide, or would align cost pressures into one general rate case.

Q. **Mr. Thomson points to the most recent three general rate cases as evidence that it is "not highly uncertain but highly likely that the future test period would be used to capture the costs and benefits of the Combined Projects in a single, timely GRC." (Thomson Surrebuttal and Supplemental Rebuttal, lines 29–31.) Do you agree?**

A. No. As acknowledged by Mr. Thomson, in two of the last three general rate cases, the test period was not contested because it was stipulated to in prior general rate case settlements. Only looking at the last three cases presents a skewed view of the litigation context for test periods in general rate cases. Table 1 below shows the history of test periods in the last 10 years of Utah general rate cases.

Table 1: Utah GRC Test Period History			
Docket No.	**Proposed Test Period**	**Contested?**	**Test Period Result**
13-035-184	June 2015	No, Stipulated	June 2015
11-035-200	May 2013	No, Stipulated	May 2013
10-035-124	June 2012	Yes, Litigated	June 2012
09-035-23	Dec 2010	Yes, Settled	June 2010
08-035-38	June 2009 (year end rate base)	Yes, Litigated	Dec 2009 (average rate base)
07-035-93	June 2009	Yes, Litigated	Dec 2008

As shown in Table 1, test period has been a contested issue in every single Utah general rate case other than those that were pre-determined in the settlement in the prior rate cases. Furthermore, in the instances where test period was contested, only one case resulted in the final test period being the one originally proposed by the Company. Since no settlement exists here, Mr. Thomson's statement that based on history it is "highly likely" the Company would be able to capture the costs and benefits in a single rate case through its proposed test period has no basis.

Q. Why do you find the OCS's position in this docket particularly troubling?

A. OCS witness Ms. Ramas dismisses the Company's proposal for the RTM to enable a proper matching of costs and benefits as unnecessary, claiming that the Company can simply "modify the anticipated timing of its next rate case and the test year utilized in that case." (Ramas Second Rebuttal, lines 154–156.) Yet, in past general rate cases, OCS has frequently opposed the Company's proposed test period. In fact, in the most recent general rate case where the test period was contested, Docket No. 10-035-134 ("2010 GRC"), OCS filed testimony proposing a forecast test period closer in time than the Company's proposed test period. As support for this argument, the OCS witness stated:

> Our test period proposal acknowledges that *new capital investment* and increases in net power costs appear to be *key drivers* underlying the Company's rate request, but it strikes an appropriate balance between ratepayers and shareholders in achieving a fair and reasonable outcome. *In particular, the Company has other cost recovery processes for major plant additions (MPA) and an energy balancing account (EBA) to address the costs of major plant investment and net power cost variations between rate cases*. (Docket No. 10-035-124, Test Period Phase Direct Testimony of Dan Gimble for the Office of Consumer Services, lines 15–59 (emphasis added).)

OCS advised the Commission in the 2010 GRC that, when selecting a test period, it should give weight to the fact that the Company has alternative avenues for cost recovery. Based on this, OCS claimed a test period that fully includes the new capital investment, a key driver in the rate case, was not necessary. But in this case, OCS is taking the opposite position—alternative avenues for cost recovery (the RTM) should not be used; instead, the Company should use a general rate case and should be able to file a reasonable test period that allows for cost recovery.

These contradictory positions are even more troubling when coupled with the fact that Ms. Ramas also calls the Company's proposal to remove the benefits of the cost-free wind generation from the Energy Balancing Account ("EBA") if the RTM is not approved "fictitious." Essentially, OCS appears to be arguing that, contrary to the normal principle that matches costs and benefits in rates, the Company should bear the costs of the Combined Projects for as long as possible, while the benefits of the generation flow through to customers in the EBA.

Q. Ms. Ramas also raises concerns that the expected timing of the Company's next general rate case with a 2021 test period would reflect base rates with the revenue requirement for the Combined Projects at its highest point until a subsequent rate case. (Ramas Second Rebuttal, lines 157–178.) Is this a valid concern?

A. No. Ms. Ramas argues that the Company should use a traditional rate case to begin recovery of the costs of the Combined Projects and questions my assertion that obtaining a future test period that would fully incorporate the Combined Projects is uncertain. But, at the same time, she criticizes the anticipated test period I identified for the Company's next general rate case, which would align several cost pressures into one case. Ms. Ramas's criticism underscores my concern that setting a future test period can be contentious and lead to the need for back-to-back general rate cases.

Q. Mr. Thomson reiterates that back-to-back rate cases have been used in the past to incorporate new significant rate base additions into base rates and concludes that "creating another mechanism in this case is unwise." (**Thomson Surrebuttal and Supplemental Rebuttal, line 62.**) **Do you agree?**

A. No. Mr. Thomson provides no reason for his conclusion that the expense, complexity, and burden of back-to-back rate cases is a better choice than establishing an RTM to match costs and benefits of a specific identifiable project as an interim measure to avoid multiple general rate cases. Because the costs and benefits of the Combined Projects can be measured and recovered through an RTM on a short-term basis, without the complexity and expense of a general rate case, all parties' resources are better used, which also benefits customers.

Q. Ms. Ramas points to the Company's cost recovery history of Cholla, Craig, Hayden, and Chehalis pointing out the Company did not receive recovery outside of a general rate case through a separate mechanism. Is this a valid reason to reject the RTM?

A. No. Once again, Ms. Ramas relies on general rate cases as the ideal venue for cost recovery. As previously stated, the Company objects to the claim by the OCS that the Company should be limited to obtain cost recovery through one or more general rate cases while the benefits of the zero-fuel-cost energy flow through to customers through the EBA. The generation plants Ms. Ramas cites were not zero-fuel-cost resources for which benefits would flow 100 percent through a fuel-cost mechanism. The fact that these resources were recovered through a general rate case does not mean that is the optimal option for recovery in this case. The Company has worked hard to limit the number of rate cases it files, recognizing the challenges that multiple rate cases can present to the Commission and the Company's customers.

Q. Did the DPU comment on your statement on lines 245–246 in your Rebuttal and Supplemental Testimony that, if a deferral is used, then the net power cost benefits of the zero-fuel-cost energy should be pulled from the EBA and deferred as well?

A. Yes. Mr. Thomson states that the DPU would not object to deferring the net power cost benefits as part of a Commission-approved deferred accounting order until the next general rate case. (Thomson Surrebuttal and Supplemental Rebuttal, lines 187–190.) Although he expresses reservations that a proper method for calculating the benefits could be difficult, the recognition that, in principle, costs and benefits should match, is a more reasonable position than OCS's. I would also note that the RTM is a simpler approach than attempting to determine a proper method for calculating the net power cost benefits to be removed from the EBA if the deferral approach is used. Nevertheless, a method for calculating the net power cost benefits was already provided in my direct testimony. Specifically, the Company proposed valuing any incremental energy from the Wind Projects using a monthly market price less wind integration. (*See* Direct Testimony of Jeffrey K. Larsen, lines 214–230.)

Q. Mr. Thomson continues to argue that, if an accounting order deferral is used, there should be no carrying charges and cites a number of examples where carrying charges were not applied to deferred accounts. (Thomson Surrebuttal and Supplemental Rebuttal, lines 65–122.) Do you agree these are reasonable precedents or support for his position in this case?

A. No. The examples of deferrals for which there was no carrying charge were all due to agreements in stipulations. As the Commission is well aware, stipulations are the outcome of a negotiation in which there is give and take among all parties. As there is no stipulation in this proceeding, and as Mr. Thomson points out, stipulations are not precedential, the comparisons are inapplicable and inappropriate in this proceeding.

Q. Does Mr. Thomson make other suggestions with regards to carrying charges?

A. Yes. Mr. Thomson states that the Commission may want to allow carrying charges on the zero-fuel-cost energy due to the fact that it is a fuel-related item. He also suggests that any deferral related to the PTC benefit should not receive a carrying charge since it is not a fuel-related item. (Thomson Surrebuttal and Supplemental Rebuttal, lines 124–132.) Mr. Thomson seems to deem fuel-cost items as being carrying-charge "eligible," while any other item is not. There are many examples of deferred accounting orders that have carrying charges that are not fuel related. Just because the EBA has a carrying charge, and Mr. Thomson can point to a few examples of deferred accounting stipulations without carrying charges, does not imply a standard that fuel-related items are worthy of a carrying charge and other deferred costs are not.

Q. What is the Company's recommendation for carrying charges?

A. The Company believes the RTM should be approved as the best way to align the costs and benefits in a timely manner with a carrying charge based on the most recently-approved Commission rate (currently 4.09 percent). The Company also recommends that if the RTM is not approved and deferred accounting is used instead, the use of a carrying charge should be consistent among *all* components of the deferral, with no special treatment of fuel-related items.

Q. Ms. Ramas states that the Company has not provided evidence that it would be unable to earn its allowed rate of return if the RTM is rejected. (Ramas Second Rebuttal, lines 151–153.) Is an earnings test an appropriate measure to determine whether to establish a mechanism for cost recovery?

A. No. The fact that the Company's most recent historical earnings may have been comparable to the Company's authorized rate of return does not mean that the Company's future earnings will be sufficient. The RTM is designed to allow the Company to match the costs and benefits of the Combined Projects and align several cost pressures into one case. The decision about whether the costs for these resources are prudent and should be included in rates is independent from other issues that would be reviewed during a general rate case; in other words, the same audit on the Combined Projects' actual costs should occur whether recovery is through the RTM or in a general rate case.

Q. Ms. Ramas again raises the argument that the shareholders will earn a return while the customers may or may not see benefits, dismissing your rebuttal that return is a normal part of a utility's cost of service. (Ramas Second Rebuttal, lines 207–262.) How do you respond?

A. Ms. Ramas's premise is that the Company's recovery of its cost of service, including a regulated return on its capital costs, is a reason the Company's request should be rejected. As I stated in my supplemental rebuttal testimony, this is contrary to basic ratemaking and the foundation of the regulatory compact. The Company does not dispute that when one adds new rate base, a higher return is earned, all else equal. But this is irrelevant to the determination of whether the Combined Projects deliver substantial customer benefits and are in the public interest. The return of and on the Company's investment is included in the Company's economic analysis, which demonstrates net benefits to customers under virtually all scenarios modeled.

Q. Mr. Peterson argues in his surrebuttal testimony that there were significant differences between the Combined Projects and the Company's acquisition of the Chehalis power plant. Do you agree there were differences?

A. Yes, there are differences, but those differences do not undermine the comparison I made. In many ways, the Combined Resources are a more compelling and less-risky investment for customers due to (1) the availability of PTCs to offset many of the costs, (2) the selection of the Wind Projects through a competitive solicitation endorsed by independent evaluators in both Utah and Oregon, and (3) the fact that the Wind Projects will provide emission-free, zero-fuel-cost energy.

RESPONSE TO PROPOSED CONDITIONS FOR APPROVAL

Q. Mr. Hayet continues to recommend that the Commission impose unprecedented conditions on approval of the Combined Projects to effectively shield customers from all risks associated with the projects. (Hayet Second Rebuttal Testimony, lines 948–981.) Has the Company's position regarding these conditions changed?

A. No. Mr. Hayet's recommendations remain entirely unreasonable and unjustified given the nature of the resource decision at issue in this case, and the provisions of Utah's resource approval laws. Again, the Combined Projects are no different in this respect from any other utility investment and do not warrant extraordinary and unprecedented conditions.

Q. DPU, OCS, and the Utah Association of Energy Users/Utah Industrial Energy Consumers claim that the Company has refused to assume any of the risk of the Combined Projects. Is this true?

A. No. First, it is my understanding that the resource decision approval statutes provide substantial customer protections under both the Significant Energy Resource Approval in Utah Code Ann. § 54-17-303 and -304, and Voluntary Request for Resource Decision Review in Utah Code Ann. § 54-17-403 and -404. Section 54-17-303(1)(a)(iii) limits cost recovery in a rate case or other proceeding to "up to the projected costs specified in the commission's order issued under Section 54-17-302." Any increase from the projected costs specified in the order must be reviewed in a general rate case. (Utah Code Ann. § 54-17-303(1)(c)). The cost recovery section in the Voluntary Request for Resource Decision Review (Utah Code Ann. § 54-17-403) provides the same protection. Notably, Section 54-17-303(1)(a)(iii) allows for recovery up to the projected costs *in either* a general rate case or other appropriate commission proceeding, while Section 54-17-303(1)(c) allows for a review of costs in excess of the projected costs in *only* a general rate case. This is entirely consistent with the Company's proposal in this case with the RTM capped at the estimated costs.

Therefore, approval of the resource decision for the Combined Projects in this application does not shield the Company from risks of cost-overruns. The Company continues to bear the risks of cost-overruns unless and until it can demonstrate prudence in a general rate case. Additionally, the Company bears the risk that if there is a change in circumstance or projected costs, it will seek a Commission review and determination on whether the Company should proceed with implementation, in accordance with Utah Code Ann. §§ 54-17-304 and -404.

Second, other than costs, the largest risk to ensure customer benefits is tied to qualifying the Wind Projects for the PTCs. As previously stated in testimony, the Company assumes the risk that the Wind Projects will qualify for the PTCs, noting the exception of factors outside of its control such as force majeure events and changes in law. (Crane Supplemental Direct and Rebuttal, lines 203–210.) What this means is that to the extent any new wind project or turbine fails to qualify for PTCs, in whole or in part other than under the noted exceptions, PTCs will be imputed to each such project based on that project's actual wind output for equipment placed in service and included in rate base at full revenue value (*i.e.*, including full gross up for federal and other applicable taxes). If there is a force majeure event or change in law during the implementation and construction of the Combined Projects, the Company will make a filing for Commission review, in accordance with Utah Code Ann. §§ 54-17-304 and -404.

Q. What are the projected costs that the Company is seeking approval of in this proceeding?

A. Confidential Table 1 shows the projected capital costs without the Uinta project and the source.

Confidential Table 1 - Calculation of Capital Costs

	In-Service Capital ($ million)	**Source**
Wind Resource Capital Costs	$1,455	Confidential Exhibit RMP__(RTL-1SS)
Interconnection Network Upgrades	$111	Confidential Exhibit RMP__(RTL-1SS)
Aeolus-to-Bridger/Anticline Transmission Line	$679	Confidential Exhibit RMP__(RTL-1SS)
Sub-Total Capital Costs as Filed	$2,245	
Remove Uinta Capital Costs	[redacted]	Confidential Exhibit RMP__(RTL-1SS)
Remove Uinta Interconnection Network Upgrades	[redacted]	Confidential Exhibit RMP__(RAV-2SS)
TOTAL Capital Costs Without Uinta	[redacted]	

Parties will have the opportunity to verify actual costs as part of the annual audit of the EBA and RTM deferred balance.

Q. Dr. Zenger is proposing that the Commission consider the status of the 2017 Protocol that expires on December 31, 2019, in reviewing the Company's request for resource approval. (Zenger Supplemental Rebuttal and Surrebuttal, lines 372–382.) Likewise, Mr. Vastag expresses concerns related to the current Multi-State Process ("MSP") and recommends that Mr. Hayet's cost caps should be adopted to address these concerns. (Vastag Second Rebuttal, lines 82–92.) Are these reasonable recommendations?

A. No. This is contrary to the 2017 Protocol currently approved for inter-jurisdictional cost allocation in the state of Utah, which uses dynamic allocation factors. Moreover, any change to inter-jurisdictional cost allocations in the future will be approved by the Commission and should not by restricted by this proceeding. In effect, Dr. Zenger and Mr. Vastag are recommending that the Commission pre-determine the outcome of the current MSP, which would be detrimental to the continuing negotiations with stakeholders throughout the Company's service area. In addition, as I previously explained in testimony, if Utah's allocated costs associated with these projects are fixed, then the benefits, including PTCs and reduced net power costs, must also be fixed. (Steward Supplemental Direct and Rebuttal, lines 365–382.) Any change of this type would require resource subscriptions that are not allowed under the 2017 Protocol and have not yet been agreed to in the MSP.

UPDATED RTM CALCULATION

Q. Have you updated the exhibits from your second supplemental testimony to reflect the costs for the Combined Projects without the Uinta wind project?

A. Yes. Confidential Exhibit RMP___(JRS-1SR)[1] reflects the updated costs and benefits in the economic analysis in Mr. Link's testimony without the Uinta project. The exhibit is in the same format used in my previous testimony as Exhibit RMP__(JRS-2SS). It calculates the annual revenue requirement and shows the overall net impact for the Combined Projects that would be reflected in rates without Uinta, including the proposed RTM.

Q. What are the updated annual estimated rate impacts associated with the Combined Projects that 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 ($3) million to $28 million in Utah, as shown in Table 1 of Confidential Exhibit RMP___(JRS-1SR). The net rate impact would be approximately 1.4 percent for the first full year of operation.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[1] Exhibit RMP__(JRS-1SR), page 2, is marked confidential in order to retain the confidentiality of the Uinta project costs.

REDACTED
Rocky Mountain Power
Exhibit RMP___(JRS-1SR)
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Joelle R. Steward

Example RTM Deferral Calculation

May 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	(7,574)	66,117	52,977	38,465
2	Utah Allocated	(3,229)	28,161	22,561	16,375
3	Utah EBA	(5,275)	(34,889)	(35,323)	(35,944)
4	Utah Deferral	2,047	63,050	57,883	52,319
5	Net Customer Impact	(3,229)	28,161	22,561	16,375

REDACTED

PacifiCorp
Utah
Combined Projects - Example Annual RTM Deferral Calculation
Revenue Requirement

[redacted]