ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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October 19, 2017

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. 17-035-39
APPLICATION FOR APPROVAL OF RESOURCE DECISION TO REPOWER WIND FACILITIES

Rocky Mountain Power hereby submits for electronic filing its Rebuttal Testimony and Exhibits in Docket No. 17-035-39. As requested by the Commission, Rocky Mountain Power is also providing seven (7) printed copies of the filing via overnight delivery, along with a CD containing the confidential electronic copies of the testimony, exhibits, and workpapers in the file formats in which they were created.

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

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

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

CERTIFICATE OF SERVICE

I hereby certify that on October 19, 2017, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

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Rocky Mountain Power
Docket No. 17-035-39
Witness: Cindy A. Crane

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Cindy A. Crane

October 2017

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

A. Yes.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. I provide the Company’s overall policy rebuttal to the objections of the Division of Public Utilities (“DPU”), Office of Consumer Services (“OCS”), and the Utah Association of Energy Users (“UAE”) to the Company’s request for resource approval of its wind repowering project.

Q. Please summarize your testimony.

A. As the wind repowering project has developed, it has become an increasingly attractive resource opportunity for customers. The benefits are now greater and more certain, and the risks have decreased. In rebuttal to the parties’ objections to the repowering project, the Company demonstrates that it has recognized and reasonably managed all of the potential risks and concerns. This includes the risk of near-term changes in federal corporate income tax rates that could adversely affect the project’s benefits. The Company will manage this and other potential risks either through the off-ramps built into the project or by seeking additional direction from the Commission before or during project implementation.

OVERVIEW OF WIND REPOWERING PROJECT BENEFITS AND RISK MANAGEMENT

Q. Based on the wind repowering project's current status and the Company's updated analysis of benefits, costs, and risks, does the project satisfy the public interest standard for resource approval under Utah Code Ann. § 54-17-402?

A. Yes. The repowering project is the least-cost, least-risk path available to serve the Company's customers. Company witness Mr. Rick T. Link's rebuttal testimony and updated economic analysis demonstrates customer benefits of $115 million in the 20-year medium case and $471 million in the 2050 medium case—an increase of $102 million and $112 million, respectively, from the Company's original analysis. Company witness Mr. Jeffrey K. Larsen's rebuttal testimony shows how those increased benefits will flow through to customers. Company witness Mr. Timothy J. Hemstreet's rebuttal testimony and project update details the Company's extensive and ongoing efforts to minimize technical and construction risk with higher-performing equipment, fixed pricing, and penalties for non-performance. Company witness Ms. Nikki L. Kobliha's rebuttal testimony addresses how the Company has maximized production tax credit ("PTC") benefits and minimized risk related to the PTC qualification requirements. Together, this evidence shows that the repowering project satisfies the public interest standard for resource approval under Utah Code Ann. § 54-17-402.

Q. The parties argue that there remain significant risks related to qualification for the PTC. Do you agree?

A. No. As demonstrated in the rebuttal testimonies of Mr. Hemstreet and Ms. Kobliha, the Company's project development and tax teams have worked together to apply Internal

Revenue Service guidance on each relevant issue, and to calibrate the project scope, expenditures, and timelines to ensure compliance. This testimony shows that the Company has actively managed and mitigated all areas of potential PTC risk raised by the parties.

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

A. I do not. Mr. Link's sensitivity modeling is designed to capture a wide range of conditions and circumstances that could impact the economics of the repowering project. In the Company's updated economic analysis, the wind repowering project shows benefits under all sensitivities. While all resource decisions inherently include some risk, the Company has demonstrated a high likelihood that the repowering project will be beneficial to customers.

Q. Both DPU and OCS object to the wind repowering project unless the Company provides additional economic analysis, such as a facility-by-facility review and a tax sensitivity. (Peaco Direct, lines 72 - 75; Hayet Direct, lines 589 - 592.) Has the Company addressed this request for additional economic analysis to validate the benefits of the wind repowering project?

A. Yes. In direct response to these concerns, the Company's updated economic analysis includes both a facility-by-facility review of the wind repowering project and a sensitivity based on a potential reduction of the federal corporate income tax rate from

35 percent to 25 percent. As Mr. Link explains in his testimony, this additional analysis further substantiates the benefits of the wind repowering project.

Q. Based on the Company's economic analysis showing the increased benefits of the wind repowering project, has the Company updated its forecast of the near-term rate benefits of the project to Utah customers?

A. Yes. As explained in the testimony of Mr. Larsen, the Company's updated economic analysis for years 2019 through 2022 estimates a Utah customer net benefit in each year, with net benefits of up to $12.4 million by 2022. Under the Resource Tracking Mechanism proposed by the Company, these benefits will flow directly to customers.

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

A. Yes. As addressed by Mr. Hemstreet, the Company has negotiated a fixed-price, turn-key contract with General Electric for wind turbines supply and installation. It has also established precautionary off-ramps in the General Electric contract to allow it to exit the repowering project before issuing retrofit work orders if the project becomes uneconomic. The timing of the execution of the Company's turbine supply contract with Vestas also provides flexibility to allow the Company to reassess project economics, if necessary, before executing the contract.

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

A. As allowed under Utah Code Ann. § 54-17-404,[1] if there is an adverse change of circumstances that materially affects the wind repowering project's economics, the Company will seek Commission review regarding whether it should proceed with implementation of the approved resource decision. The Company will apply this approach if there are material, adverse changes in the federal tax law that occur during project implementation. But as Ms. Kobliha explains—and as OCS witness Ms. Donna Ramas also reports—the window for tax law changes is likely to close in early 2018, well before the final off-ramp for the repowering project. (Ramas Direct, lines 577 - 578.)

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

A. Yes. The Company has taken every precaution to ensure that each repowered facility will meet the requirements and timelines of the five-percent safe-harbor requirement, as well as the 80/20 test, and has developed a construction schedule and negotiated contract terms that minimize schedule risks. While we do not believe it is appropriate for the Company to absorb risks beyond its control—such as those associated with the actions of the U.S. Congress—we are prepared to accept risks associated with our

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

performance. We are confident that our 2016 investment will meet the five percent threshold of total project costs, that we will complete the repowering project well in advance of the 2020 deadline, and that the post-repowering fair market value of each wind turbine will include at least 80 percent new equipment.

Q. How will the Company respond if the federal corporate income tax rate is significantly altered, impacting the economics of repowering?

A. This depends on the extent and the nature of the change. As Mr. Link's tax sensitivity analysis shows, the repowering project remains beneficial under the reasonable assumption that a new corporate federal tax rate would not be below 25 percent, so the repowering project will be in the public interest even if the corporate tax rate is substantially reduced.

If a tax rate change occurs before the Company executes turbine supply and installation contracts in early 2018, the Company will refresh the project economics to inform its decision to proceed or terminate. The Company will either update its pending request, or if the change occurs during the implementation of the repowering project, the Company will seek guidance from the Commission under Utah Code Ann. § 54-17-404.

If the tax law change occurs after the repowering project is completed, then the change should be addressed like any other factor that occurs after a resource decision is approved by the Commission based on the facts known at the time. There is always a risk that future changes in laws could affect decisions made today, and the Company has to operate on the best information available at the time decisions are made. That is why we are before the Commission now—to determine whether the Company has adequately addressed the project risks and whether repowering is in the public interest given the information currently available.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Timothy J. Hemstreet

October 2017

REBUTTAL TESTIMONY OF TIMOTHY J. HEMSTREET

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

A. Yes.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. I provide an update on the technical and commercial aspects of the Company's wind repowering project, demonstrating the project's increasing value and decreasing risk. I also respond to the direct testimony of Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger and Daniel Peaco recommending that the Public Service Commission of Utah ("Commission") not approve the Company's energy resource decision for wind repowering.

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

A. I address the following key issues:

- A description of the fully negotiated contracts with General Electric International, Inc. ("GE") and Vestas-American Wind Technology, Inc. ("Vestas") for the wind repowering project, and associated cost-savings.
- An update on the wind turbine generator equipment specified for the wind repowering project and the increased generation benefits now anticipated as a result of changes to that equipment.
- In response to the DPU's testimony, I summarize the Company's significant efforts to date and future plans to minimize risk associated with the wind

- repowering project to ensure that the project will deliver the anticipated benefits.
- The timing and process leading up to the Company's decision to execute safe-harbor equipment-purchase contracts in late 2016, the evaluation of the repowering project in the Company's integrated resource planning process, and the appropriateness of the Commission's review of the wind repowering resource decision.

Q. Please summarize your testimony.

A. The Company has continued to work diligently on the wind repowering project to deliver benefits to its customers. The Company has finished negotiating a master retrofit contract with GE and a turbine supply contract with Vestas. The negotiated contract provisions reduce the initial estimated cost of the repowering project, increase the generation output, and reduce or eliminate various project risks. In addition, the Company has now completed most of its siting and permitting work, clearing this important project hurdle.

The DPU opposes Commission approval of the wind repowering resource decision for various reasons, mostly related to project risk and process issues. My testimony addresses each of the technical and commercial risks raised by the DPU. I show that the Company has aggressively managed these risks and none outweigh the customer benefits from repowering. I also demonstrate that the Company timely raised wind repowering in its 2017 Integrated Resource Plan ("IRP"), and has appropriately invoked the resource approval statute to obtain Commission review and approval of wind repowering.

UPDATE ON CONTRACT STATUS

Q. At the time you prepared your direct testimony, the Company was still negotiating a turn-key agreement with GE for the wind repowering project employing GE equipment. Has the Company now completed these negotiations?

A. Yes, the Company has completed negotiating a master retrofit contract that commits GE to perform turn-key supply, delivery, installation and commissioning of the repowering turbines at a fixed price.

Q. Does the fully negotiated GE retrofit contract reflect differences in pricing compared to the previous estimate used in the Company's economic analysis?

A. Yes, the negotiated contract reduces the pricing for those wind facilities that will be repowered using GE turbines. [redacted]

Q. Does this mean that the Company has committed to move forward with the wind repowering project regardless of the Commission's determination in this case?

A. No. The GE retrofit contract provides an off-ramp if the Company does not obtain regulatory approval for the repowering project or any approval that includes conditions that present a material concern to the Company in moving forward with the repowering project.

Q. Does the GE retrofit contract provide other off-ramps to address potential changes in circumstances that may affect the economics of the wind repowering project or the ability of the Company to execute the project as currently anticipated?

A. Yes. The GE retrofit contract allows the Company, before issuance of a retrofit work order directing GE to repower a facility, to not move forward with the retrofit work for a number of reasons. These include situations in which the Company was not able to timely obtain any required permit, or if the terms and conditions imposed by a permit are unacceptable to the Company; for technical reasons related to the suitability of the new turbines for the site or existing foundations; the Company's determination that changes in local, state, or federal law or corporate tax law create a material risk to the project; or if the federal production tax credit ("PTC") law or Internal Revenue Service ("IRS") guidance regarding PTCs (including the safe-harbor requirements or the 80/20 Rule) is adversely modified, amended, or changed.

Q. When does the Company anticipate issuing its first retrofit work order to repower a GE facility?

A. The first retrofit work order is expected to be issued in [redacted] to allow turbine delivery to begin in time to support repowering of facilities in 2019.

Q. If a retrofit work order is issued to GE for a facility and tax law changes, new permit requirements, or changes in PTC rules occur and those off-ramps are no longer automatically available to the Company, what recourse would the Company have?

A. Following the issuance of a retrofit work order, the GE retrofit contract has provisions that allow the Company to terminate the retrofit work order for convenience at known costs that escalate from the date the retrofit work order is executed up to the date of the first anticipated turbine delivery. Thus, the Company will still have the ability to respond to potential changes in the legal framework that may impact the value of the GE repowering facilities.

Q. Has the Company also completed negotiations on a turbine supply contract with Vestas?

A. Yes. The Company has completed negotiations with Vestas and has fixed pricing for turbines ordered [redacted].

Q. Do the two contracts with the turbine suppliers provide for the costs of the turbines (and installation in the case of GE) to be adjusted up or down for factors such as inflation, currency indexes, or steel price indexes?

A. No, the contracts provide that the prices are fixed and have no such adjustment mechanisms for those common price indexes. Generally, the turbine suppliers can only seek a change order for price relief as a result of changes in state and/or local law that impacts their costs.

UPDATE ON TURBINE SPECIFICATIONS AND ENERGY OUTPUT

Q. Please provide an update on the turbine equipment specified for use in the wind repowering project.

A. In my direct testimony, I noted that GE was developing a 91-meter rotor for repowering at wind facilities, like the Company's, that currently have GE 1.5-77 SLE turbines installed. GE finished developing this rotor and has completed the engineering and design review on a [redacted] turbine, which the Company can use to repower its [redacted]. The nameplate capacity of the generator of this turbine is [redacted] megawatts greater than the [redacted] turbine previously specified.

Q. Has GE evaluated this new turbine to ensure it can be used to repower the Company's [redacted]?

A. Yes, GE has completed a mechanical loads analysis for the new turbine type at each of the Company's [redacted] sites. The mechanical loads analysis is an engineering study to assess the site-specific climatic conditions and turbine loading to verify that the turbine is suitable for use at the facility site with the existing towers.

Q. Has the Company also verified that the existing foundations at these wind facilities are suitable for use with the new turbine, which may have different loading due to the larger rotors?

A. Yes, the Company's consultant Black & Veatch reviewed the new foundation loading at each facility site and determined that the existing foundations at the facilities can support the new turbines.

Q. Does the change in turbine specification for the wind facilities require modification to the nacelles purchased to meet safe-harbor requirements?

A. No, the existing nacelles the Company acquired from GE in December 2016 can be operated as a [redacted] turbine.

Q. What are the energy benefits of this new turbine type?

A. The increase in rotor diameter allows the wind turbine to capture additional wind energy, while the higher nameplate capacity allows the turbine to convert more of that available wind energy into electrical energy at higher wind speeds. Previously the

Company expected the generation output of the wind facilities to be fitted with GE [redacted] wind turbines to increase by 13.3 percent. The new GE [redacted] wind turbine results in an increase of 22.4 percent. Confidential Exhibit RMP__(TJH-1R) provides an update on the energy estimates for the repowering project.

Q. Does this new turbine selection for the wind facilities require additional modifications, like changes in the towers, substations, or the energy collector systems?

A. No. If operated within the limits of the existing large generator interconnection agreements, the Company does not anticipate that any such modifications are necessary.

Q. What is the net result of the changes in equipment specifications to the amount of additional energy expected to be produced as a result of repowering?

A. Assuming the generation interconnection agreements of the projects are not modified, the repowering project is estimated to result in an additional 743 gigawatt-hours ("GWh") of energy annually, or an overall increase of 25.9 percent. This compares to the 551 GWh and 19.2 percent increase in energy output estimated previously in the Company's Application. If the generation interconnection agreements are modified to allow all of the turbines to operate at their full nameplate capability during periods of higher winds, the generation benefits increase to 862 GWh, or 30.0 percent.

Q. Given the changes in turbine equipment that can generate additional energy, have the estimated costs of the repowering project increased?

A. No. The Company has fixed pricing for the turbines from GE and Vestas and for installation of the GE project turbines. Costs for turbine supply at each facility have either not changed from prior estimates or decreased. As a result, the total cost of the repowering project is now $1.083 billion—a reduction in cost of $45 million.

Q. If the generation interconnection agreements are modified, does the Company expect there will be additional costs to realize that additional generation?

A. Yes. Due to the higher nameplate capacity of the GE [redacted] turbines, enabling them to operate at full capacity would require replacing the turbine pad-mount transformers, upgrading some segments of the collector systems, and retrofitting or replacing certain generator step-up transformers. The Company expects the total cost of these upgrades to increase project costs by $36 million, for a total cost of approximately $1.119 billion. In addition, ongoing transmission studies will determine the costs of interconnecting the additional project capacity to the transmission system.

Q. Are there other updates to the project since the Company filed its request for resource approval?

A. Yes. The Company has also negotiated [redacted].

[redacted]

[redacted]

Q. Does the Company's updated economic analysis reflect the costs of this fully negotiated contract?

A. Yes. The Company's updated economic analysis reflects higher operations and maintenance costs [redacted] and reduced capital expenditures at the projects [redacted]. Capital expenditures are reduced for the [redacted].

Q. Are all of these changes reflected in the economic analysis in the rebuttal testimony of Company witness Mr. Rick T. Link?

A. All of the costs associated with these changes are reflected in the updated economic analysis described by Mr. Link. However, the Company did not receive verification from GE that the [redacted] turbine was technically suitable for its repowering project until October 6, 2017. As a result, Mr. Link's detailed analysis evaluates the energy output assuming a GE [redacted] turbine is used on sites that will be repowered with GE equipment instead of a GE [redacted] turbine—the difference being that the [redacted] turbine has the same cost as the GE [redacted] turbine but higher energy output as a result of a greater generator capacity.

REBUTTAL ON RISKS OF REPOWERING PROJECT

Q. DPU witnesses Dr. Joni Zenger and Mr. Daniel Peaco oppose Commission approval of the Company's repowering resource decision on the basis that the project risks outweigh the potential benefits. (Zenger Direct, lines 55 - 60; Peaco Direct, lines 72 - 75.) Please respond.

A. I strongly disagree with the DPU's conclusion and rationale. Wind repowering has clear and immediate benefits to customers, and the Company has identified and managed project risks and will continue to successfully manage those risks. The DPU's testimony does not properly account for the steps the Company has already taken to eliminate or mitigate the risks they identified. On each issue raised by the DPU, the Company can demonstrate that it has considered and prudently managed project risk, as set forth below.

Q. When discussing risks related to the repowering project qualifying for PTCs, Mr. Peaco states that the Company's 2016 safe harbor expenditures for four of the repowering facilities are less than 6.7 percent, and that these margins "do not leave a large room for error in compliance with the rule." (Peaco Direct, lines 658 - 662.) Do you believe that potential cost overruns pose a substantial risk to the ability of the project to qualify for the full value of PTCs?

A. No. The wind repowering project has a great deal of cost certainty because it involves equipment replacement rather than new construction. Cost and scope uncertainties that can increase costs are largely absent from this project. This is because the repowering project will not involve the construction of new roads, turbine foundations, substations or operations and maintenance buildings—where changed site conditions or uncertain geotechnical conditions can create cost uncertainty.

Q. Why is there little risk of not meeting the safe harbor requirement in this case?

A. The cost of the wind repowering project consists mainly of turbine supply costs which are fixed and set forth in fully negotiated turbine supply contracts with both GE and Vestas. In the case of the GE projects, the Company's fixed-price turn-key contract also includes turbine installation. To put the risks Mr. Peaco raises in perspective, Confidential Table 1 below shows the applicable project costs subject to the five percent safe-harbor requirement for each facility, as well as the current safe-harbor percentage for each facility given the Company's current cost estimates and allocation of 2016 safe-harbor equipment. Confidential Table 1 also shows the amount and percentage of each facility's costs that are now fixed under the Company's negotiated contracts.

Under these contracts, cost overrun exposure is largely limited to the aspects of the repowering scope that are not yet subject to negotiated, fixed-price contracts. As shown in the table, the non-fixed project costs could escalate between 100 percent and 5,300 percent and each facility would still be able to comply with the five percent safe-harbor requirement. In the worst case scenario, the Company's cost estimates, which have been informed by budgetary quotes from wind energy construction companies and reflect its experience constructing and maintaining these very same wind projects, can be exceeded by 100 percent and still qualify under the five percent safe-harbor rule.

Confidential Table 1
Cost Overrun Sensitivity of Repowering Facilities to Meet Five Percent Safe Harbor

Wind Project	Total Project Cost Applicable to Five Percent Safe Harbor ($000s)	Current Safe Harbor Percentage (%)	Cost that are Fixed with Turbine Suppliers ($000s)	Turbine Supplier Fixed Costs (%)	Costs Not Yet Contractually Fixed ($000s)	Amount that Non-Fixed Costs Can Increase and Meet 5% Safe Harbor (%)
McFadden Ridge	[redacted]					
Seven Mile Hill II						
High Plains						
Dunlap I						
Glenrock III						
Glenrock I						
Rolling Hills						
Seven Mile Hill I						
Marengo I						
Marengo II						
Leaning Juniper						
Goodnoe Hills						

Q. The Company produced detailed construction cost estimates in discovery in this case. Has any party questioned specific aspects of the Company's construction cost estimates or identified cost elements the Company has underestimated or overlooked?

A. No.

Q. Do you believe the contracting mechanisms the Company intends to use for the majority of the non-fixed costs shown in the table above create risk of potential cost overruns?

A. No. The majority of the non-fixed costs are turbine installation costs not already covered by a contract. The Company—as it has traditionally done for its wind energy development construction projects—will execute fixed-price contracts for all turbine installations so that the costs are known in advance and not subject to variability except for standard provisions that allow the installer to seek price relief (e.g., force majeure, change in law).

Q. Are there other actions the Company can take to mitigate the risk associated with the five percent safe harbor?

A. Yes. As discussed in the rebuttal testimony of Ms. Nikki L. Kobliha, the Company could reallocate safe-harbor turbine components among facilities if a specific facility is experiencing cost overruns. This would increase that facility's safe-harbor percentage, ensuring it equals or exceeds five percent.

Q. What if the Company determined, after the equipment was already installed, that the five percent safe-harbor requirement was not met. Would that result in the entire project losing its full PTC value?

A. No. As described in Ms. Kobliha's rebuttal testimony, in such a case, the Company would simply reduce the scope of its repowering project to exclude a specific turbine or turbines, thereby reducing the overall project cost such that the allocated PTC safe-harbor equipment is sufficient to satisfy the five percent requirement. This would allow those turbines that remain within the defined project to qualify for the full value of PTCs. As demonstrated by the fact that the Company will not be repowering 32 turbines at the Glenrock/Rolling Hills site because they would not meet the 80/20 test, the Company is free to define the number of turbines at a facility site that it is including within its wind repowering project.

Q. Wouldn't that affect the economics of the project since individual turbines would be left out of the project and not generate PTCs?

A. Yes, but it would preserve full PTC qualification for nearly all of the wind repowering project and thus does not materially affect the overall project economics.

Q. When implementing projects like the wind repowering project, does the Company have personnel and processes to track costs and ensure awareness of forecasted and actual project spending throughout the project?

A. Yes, for all capital projects of this scale, the Company has assigned project managers who work with the Company's construction management, finance and accounting staff to forecast and accrue project costs and track project invoices and contract payments such that any cost changes are identified as they occur. The Company can use this information to make any needed adjustments to manage the limited risk of potential cost overruns.

Q. For the wind facilities the Company has previously constructed, has the Company ever had an issue in meeting the applicable IRS requirements such that the projects did not qualify for PTCs?

A. No.

Q. Do you believe there are material risks that the 2016 safe-harbor purchases could be inadequate?

A. No. As shown in Confidential Table 1, the only realistic potential for cost overruns to impact the adequacy of the 2016 safe-harbor purchases [redacted]. Thus, before committing to the project, the Company will have certainty that cost overruns for those facilities pose no threat to the adequacy of the 2016 safe-harbor equipment. Should there be a potential for the 2016 safe-harbor equipment to be insufficient to cover anticipated project costs, the Company will have the ability to address those risks as described above.

Q. How do you respond to Mr. Peaco's testimony that the Company has not provided any analysis of the risk of potential cost overruns causing the 2016 safe-harbor expenditures to be insufficient? (Peaco Direct, line 667.)

A. The Company has assessed and addressed the safe-harbor risk since the inception of the project. For example, the Company acquired safe-harbor equipment sufficient to achieve a six percent safe-harbor to ensure adequate coverage. The Company has also taken the steps described above to ensure certainty around project costs and will continue to monitor these costs. Because it is highly unlikely that the Company's cost estimates will be off by 100 percent or more, an economic analysis or sensitivity around these risks, as Mr. Peaco suggests, is not productive or necessary.

Q. Has Mr. Peaco proposed a methodology the Company should use to assess these risks?

A. No.

Q. Mr. Peaco also alleges that there is risk that the repowered facilities may not be in service by the end of 2020 due to the possibility turbines, contractors or equipment may not be available. (Peaco Direct, lines 697 - 699.) Do you believe this is a significant risk to the project or its economics?

A. No. As noted above, for the [redacted] wind facilities, the Company already has a fully negotiated contract with GE to perform repowering on a turn-key basis and thus has secured the equipment and resources to complete those projects. The Company has also negotiated a turbine supply contract with Vestas and will be able to secure those turbines. GE will be contractually obligated to complete repowering by guaranteed completion dates that will be specified by the Company. The Company plans to complete seven of the [redacted] facilities before the end of 2019—a year ahead of the required December 31, 2020 deadline for the repowered facilities to achieve commercial operation. Thus, there is little risk of those facilities not meeting the 2020 deadline. The Dunlap facility is the only facility the Company is planning to repower in 2020 to avoid significantly truncating the existing PTCs from that facility.

Q. Does the Company have any remedies if GE does not meet a guaranteed turbine-completion date for a wind facility?

A. Yes. If the delay is not caused or otherwise agreed to by the Company or due to certain strictly limited "excusable delay" events, and the Company has met its contract requirements, GE will be required to pay liquidated damages to the Company of [redacted] per day for any turbine that is not completed by a guaranteed turbine-completion date, [redacted]. In addition, as discussed in more detail below, if there is any slip in the turbine-completion date beyond December 31, 2020, [redacted]. These mechanisms in the GE contract create a powerful incentive for GE to maintain the contractual schedule.

Q. Mr. Peaco alleges that the Company has not "provided any mechanism for damage recovery due to 'lost' PTC." (Peaco Direct, lines 709 - 712.) Does the GE contract provide any remedies to the Company if the repowered facilities (or individual turbines within those facilities) fail to qualify for PTCs as a result of not being placed in service by December 31, 2020?

A. Yes. Under the terms of the GE retrofit contract, [redacted]

[redacted]

Q. Mr. Peaco also cites permitting and financing risks as having the potential to cause a delay in repowering the facilities, threatening their ability to qualify for PTCs. (Peaco Direct, lines 694 - 699.) Do you agree?

A. No. The Company has now received notice from the Wyoming Industrial Siting Division that no amendments to its existing operating permits for the Wyoming wind facilities are necessary to complete the repowering project. Similarly, the Company has received notice from Columbia County, Washington, that its conditional use permit for

[redacted]

the Marengo facility need not be modified and that no additional permits are needed to repower the facility. The Company now has the major permit authorizations for 10 of the 12 facilities proposed for repowering. I do not expect any issues in obtaining required regulatory approvals for the remaining two facilities.

Q. Mr. Peaco alleges that the Company has not assessed the risks related to potential lost PTC revenue as a result of permitting delays. (Peaco Direct, lines 694 - 702.) Please respond.

A. The Company will not order further turbines (beyond those already procured to satisfy the safe-harbor requirements) or otherwise move forward with the repowering project until it has secured the necessary permits—a task that is near completion. For this reason, permitting issues are not a material risk to achieving the benefits of the repowering project.

Q. What about the risk Mr. Peaco raises that repowering costs could be less than anticipated such that the 80/20 rule is not met due to insufficient expenditures? (Peaco Direct, lines 734 - 735.)

A. Given the fixed-priced contracts that the Company has negotiated for turbine supply and installation, there is very minimal risk that the Company could underspend on repowering costs such that a turbine failed the 80/20 test. In Confidential Table 2 below, I show the preliminary Ernst & Young valuation for each turbine type that the Company proposes to repower, based on a December 31, 2018 valuation date. Also shown is the required spending necessary to meet the 80/20 Rule, the anticipated spending per turbine, and the amount by which the anticipated spending is over the 80 percent threshold. As shown in the table, the turbines with the highest estimated fair market value of the retained components still have spending [redacted]. I am confident that cost under-run risk does not pose a significant threat to the ability of the projects to meet the 80/20 test. In addition, the turbines with the lowest spending in excess of the 80/20 requirements are planned to be repowered in the third quarter of 2019, and their fair market value at that time will likely be less than at the end of 2018–creating additional margin above the 80/20 spending requirement.

Confidential Table 2
80/20 Rule Spending Requirements by Project

Location Name	Turbine Foundation Type	# of Turbines	Ernst & Young Preliminary FMV of Retained Components Per Turbine 12/31/2018 ($000s)	Minimum Threshold of New Turbine Costs Required ($000s)	Qualifying Machine Head Costs Per Turbine ($000s)	New Turbine Costs in Excess of Requirement ($000s)
Goodnoe Hills	Standard	47	[redacted]	[redacted]	[redacted]	[redacted]
Marengo I	Standard	78	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock I	Standard	58	[redacted]	[redacted]	[redacted]	[redacted]
McFadden Ridge	Standard	19	[redacted]	[redacted]	[redacted]	[redacted]
Rolling Hills	Standard	42	[redacted]	[redacted]	[redacted]	[redacted]
Marengo II	Standard	39	[redacted]	[redacted]	[redacted]	[redacted]
Leaning Juniper	Standard	67	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill I	Standard	57	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill I	Dynamic	9	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock III	Standard	13	[redacted]	[redacted]	[redacted]	[redacted]
High Plains	Standard	66	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill II	Standard	13	[redacted]	[redacted]	[redacted]	[redacted]
Dunlap	Standard	74	[redacted]	[redacted]	[redacted]	[redacted]
Rolling Hills	Dynamic	6	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock III	Dynamic	7	[redacted]	[redacted]	[redacted]	[redacted]

Q. Dr. Zenger states that the Company previously experienced issues with deploying safe-harbor wind-turbine generator ("WTG") equipment when technical analysis later determined that the equipment purchased was unsuitable for particular wind development sites, and suggests that the repowering project presents a similar risk. (Zenger Direct, lines 148 - 179.) Do you agree?

A. No. The Company did not execute contracts to purchase the safe-harbor equipment acquired in December 2016 until it had completed technical analysis to verify the equipment was suitable for repowering. GE prepared this technical analysis in November 2016, which provided assurances that the GE nacelles could be deployed at 237 turbine locations in Wyoming. Vestas completed similar technical analysis in late

December 2016, verifying that the Vestas nacelles were suitable for deployment at the Marengo facility, with 117 turbine locations. GE subsequently completed mechanical loads analyses for the Dunlap, High Plains, and McFadden Ridge wind facilities in February and March 2017, providing assurance that repowering the entire Wyoming wind fleet was technically feasible with the equipment acquired in December 2016. GE completed technical analysis of the GE [redacted] turbine for use at all Company sites in Wyoming on October 6, 2017. These technical evaluations—as well as the verification by the Company's consultant that the foundations are suitable to accommodate the repowering turbines—fully address the risks identified by Dr. Zenger.

Dr. Zenger's criticism of the Company's prior acquisition of wind turbines intended for an Idaho site, but ultimately used for the Rolling Hills wind facility, is also misplaced. The Company determined that Rolling Hills was the best project in which to cost-effectively use the turbines it had acquired. At the time, turbines were in short supply and it would have been difficult for the Company to cost-effectively obtain turbines for an alternative project or even obtain turbines at all had it not already acquired the turbines. Moreover, to take advantage of the value of PTCs, which were set to expire at the end of 2008,[2] the Company needed to act quickly so it could place the resource in service by the end of 2008. In the end, the Company acted reasonably and in customers' interests, as indicated by the fact that the Commission did not find the Company's development of the Rolling Hills facility imprudent.

[2] The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) passed on October 3, 2008, subsequently extended PTC eligibility to wind projects constructed by December 31, 2010, effectively extending the earlier December 31, 2008 eligibility window.

Q. Dr. Zenger also cites the Company's past experience in obtaining or extending land leases for wind projects under development as a risk related to the repowering project. (Zenger Direct, lines 182 - 187.) Has the Company verified that it has the land rights to operate its wind turbines for the anticipated extended life of the repowered wind facilities?

A. Yes, the Company has reviewed the terms for all of the leases where its wind turbines are located and has determined that, with two exceptions, the current lease expiration dates either already cover the extended asset life of the repowered wind turbines or that the Company has the unilateral ability to extend the duration of the land leases to cover the extended asset life. The first exception is Leaning Juniper, where the Company has the unilateral right to extend the lease term to January 2046. The second exception is two turbines at Marengo I that are located on State of Washington lands, where the current lease term runs through 2041. The Company has been in contact with both landowners and will work with them to extend the lease terms to cover the remaining additional years of project operations following repowering.

Q. What if the Company is unable to extend the leases for those turbines?

A. The Company would then re-evaluate the economics to determine if moving forward with a shorter lease term—or alternatively, not repowering certain turbines in the case of Marengo I—adversely impacts project economics. Because repowering the turbines is priced on a per-turbine basis, reducing the number of turbines repowered while also reducing the commensurate investment cost does not adversely impact project economics. Alternatively, it may be more prudent to wait to renew the leases until the lease expiration is closer at hand given the long time before the leases would need to be extended.

Q. Mr. Peaco alleges that the economic benefits of the repowering project are highly sensitive to the amount of energy produced by the repowered facilities, as well as the existing assets, and that there is risk to customer benefits because the Company's revenue estimates are "based entirely on assumed capacity factors." (Peaco Direct, lines 834 - 836.) Please respond.

A. I strongly disagree, with respect to both the existing and the forecast post-repowering generation from the facilities. The Company's assessment of the existing generation from the facilities, listed as Current Long Term Generation (MWh), Column 4 in Confidential Exhibit RMP__(TJH-1R), is not based on assumed capacity factors. The existing generation reflects the actual generation output from each facility since its first full year of commercial operations. It is not based on expected generation increases predicted by wind modeling nor based upon a P50 forecast of generation that may not reflect a project's actual generation history.

Q. Do the generation estimates following repowering also consist simply of "assumed capacity factors?"

A. No. The post-repowering estimates of energy production upon which the Company's current economic analysis are based also reflect the actual operating history of the wind facilities. The Company worked with its consultant, Black & Veatch, to use the extensive data history from the Company's facilities to derive precise estimates of the energy production expected from repowering. This analysis used more than 160 million data points from the operational record of the wind facilities and incorporated additional modeled wake losses anticipated from the new equipment. The results reflect as accurately as possible the energy production that would have occurred from the repowered turbines under the same operational conditions and availability as the existing equipment. Thus, the energy estimates do not rely upon assumptions about either the wind conditions that are expected to exist at the projects or improved availability as compared to the Company's actual experience.

Q. Do you believe these repowering energy estimates to be conservative?

A. Yes. The estimates reflect the generation increase that is expected to occur solely based on the different equipment performance specifications of the newer equipment. As described above, the generation estimates do not reflect any improvements in the operational availability of the wind facilities from repowering. I expect that the availability of the wind turbines will improve after repowering given the additional sensors and condition monitoring systems in the repowered turbines that should allow for improved diagnostics and implementation of preventative maintenance measures that can reduce turbine down-time. Additionally, given the [redacted], I anticipate the [redacted] availability of the projects may increase—resulting in more generation under similar wind conditions as compared to the past.

Q. Mr. Peaco states that "[w]ind generation is highly variable, and there is definite potential that actual project generation could be less than assumed." (Peaco Direct, lines 836 - 837.) Please respond.

A. While I agree that wind generation is highly variable, I do not agree that there is a definite potential that actual project generation could be less than assumed. As described above, the Company's estimates of existing energy production reflect the actual average annual generation observed over the life of the facilities. As described above, the repowering energy estimates are also derived from the actual operating history of the projects and applied to that same average baseline generation history. Thus, even with variability on a year-by-year basis, the long-term generation should revert to the mean.

Q. Does Mr. Peaco point to any specific factors in the Company's estimates of energy production that would create a bias towards an overestimation of the generation benefits from repowering?

A. No. He suggests there is potential for generation benefits to be less than anticipated due to the variable nature of wind generation, but he does not appear to ascribe a commensurate likelihood that the generation benefits could be greater than anticipated as a result of that same variability. Mr. Peaco does not provide any other rationale supporting his claim that the Company's generation estimates could be less than assumed.

Q. Mr. Peaco states that assumptions on project life have significant impacts on the customer benefits of the repowering projects and that these risks are borne by customers. (Peaco Direct, lines 869 - 874.) Do you believe the project life assumptions are biased in any way?

A. No. The Company's assumptions regarding asset life reflect the current depreciation lives of the wind facilities, as approved by the Commission. The Company's project life assumption simply reflects the reasonable assumption that equipment that is new will last 10 years longer than equipment that is already at least 10 years old.

APPLICABILITY OF VOLUNTARY RESOURCE APPROVAL STATUTE

Q. Dr. Zenger opposes the Company's request for approval of wind repowering because Utah's resource approval statute (the "pre-approval statute") does not contemplate approval of resource decisions that have "already been committed to." (Zenger Direct, lines 103 - 105.) Is this a valid objection?

A. No. As Mr. Jeffrey K. Larsen also explains in his rebuttal testimony, my understanding is that the pre-approval statute is designed to determine whether a resource decision is in the public interest before a utility implements its decision–which is the purpose of this docket. Although the Company made expenditures of [redacted] in 2016 to qualify for the full value of the PTC and preserve the option to repower the entirety of the wind fleet, the Company's expenditures to date for the wind repowering project represent only seven percent of the currently anticipated total costs of repowering. The Company's actions to date should not be interpreted as an absolute, unqualified commitment to proceed with the repowering project regardless of the outcome of this case. The Company is also not obligated contractually to either GE or Vestas to proceed with repowering or to purchase any additional equipment or services in support of the repowering project if the Commission denies the Company's request. The Company has asked for the Commission's review and approval of the repowering project—an option made economically feasible by the Company's decision to purchase safe harbor equipment in 2016—on the basis that the project is beneficial to customers and in the public interest.

Q. Dr. Zenger faults the Company for not including stakeholders in the planning process, and specifically notes the lack of a Commission-approved IRP or Action Plan identifying wind repowering as a factor relevant to the Commission's public interest determination. (Zenger Direct, lines 105 - 108, 222 - 227.) Could the Company have raised the wind repowering project early in the Company's 2017 IRP process?

A. No. The technical analysis demonstrating that it was feasible to repower any of the Company's wind facilities was not completed until November 1, 2016. On that date, GE completed a mechanical loads analysis of the Rolling Hills project (66 turbines) and a portion of the Glenrock III project (13 turbines). Subsequent mechanical loads analysis was completed for Glenrock I (66 turbines) and the remainder of Glenrock III (13 turbines) on November 3, 2016, and for the Seven Mile Hill I and II projects on November 7, 2016. Before this time, the Company did not know that repowering was feasible and did not have the information (*i.e.*, turbine types suitable for use in repowering, and their associated energy production) necessary to develop meaningful scenarios in the IRP.

Q. If the Company knew that repowering was technically feasible for at least a subset of its Wyoming wind projects in early November 2016, why did it not develop a proxy repowering scenario to include in the IRP process or state that it was contemplating repowering its wind facilities during the Company's November 17, 2016 IRP public meeting?

A. Although the Company knew in November 2016 that it was technically feasible to repower at least a portion of its Wyoming wind fleet, the Company had not completed negotiations with GE regarding equipment pricing, and it remained uncertain whether safe-harbor equipment was available—and to what extent—for delivery before the end of 2016. The Company also did not yet know whether repowering wind facilities with Vestas equipment was feasible since that technical analysis was not completed until December 22, 2016.

Q. Are there other factors that impacted the Company's ability to publicize its discussions with turbine suppliers at the end of 2016 or integrate repowering scenarios earlier in the IRP process?

A. Yes. First, only the original equipment manufacturers of the Company's wind turbines could complete the technical analysis validating whether repowering was technically feasible in time to acquire safe-harbor equipment in 2016. Thus, analysis of repowering projects within the IRP—had it been possible—would not have resulted in modeling proxy resources but rather in identifying specific projects requiring equipment from individual equipment suppliers. Public modeling of the economics of repowering—and potentially individual projects—could have disadvantaged the Company's negotiations with suppliers.

Second, safe-harbor WTG equipment was in short supply in late 2016 because it was the last year for wind projects to purchase equipment to qualify as having begun construction in 2016 and thereby qualify for 100 percent of the PTC. Thus, the Company was competing with other market participants to purchase limited safe-harbor equipment. Public information that the Company was considering repowering its wind fleet of known turbine types at known locations may have induced other market participants to evaluate repowering their own projects and could have resulted in greater competition for the limited safe-harbor equipment, increased prices, or limited turbine availability. This could have limited the Company's options for wind repowering and reduced customers' benefits.

Q. OCS witnesses Messrs. Mangelson and Hayet argue that additional analysis of the repowering project should be conducted over the next four to six months, extending the current schedule for a Commission decision on the Company's request for resource approval. (Magelson Direct, lines 56 - 59; Hayet Direct, lines 594 - 597.) Is this proposal reasonable?

A. No. In Mr. Link's rebuttal testimony, the Company has provided additional analysis of the type OCS requests, further documenting that the wind repowering project—and each individual facility proposed to be repowered—is beneficial to customers. Additionally, scheduling another four to six months to conduct more analysis and delaying the Commission's decision on the Company's request would negatively affect the viability of the repowering project. The delay would impact the ability of the Company to execute contracts in early 2018, as required to maintain the construction schedule described in my direct testimony. Given the negotiated rate of turbine deliveries and project completion durations in the Company's negotiated contracts, this would likely push projects scheduled for 2019 completion into 2020, potentially increasing project costs as a result of the change in schedule and increasing risks related to meeting the December 31, 2020 deadline.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(TJH-1R)
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Timothy J. Hemstreet

Repowering Project – Generation Increases

October 2017

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

REDACTED
Rocky Mountain Power
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Rick T. Link

October 2017

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

A. Yes.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. I summarize updates to the economic analysis that demonstrate increasing customer benefits from the wind repowering project. I also rebut challenges to the Company's economic analysis raised in the direct testimonies of the Utah Division of Public Utilities ("DPU") witness Mr. Daniel Peaco; Office of Consumer Services ("OCS") witnesses Mr. Philip Hayet, Ms. Donna Ramas, and Mr. Gavin Mangelson; and the Utah Association of Energy Users ("UAE") witness Mr. Kevin C. Higgins.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony summarizes updated and expanded economic analysis that incorporates modeling updates and new sensitivity studies developed in response to certain concerns raised by parties in this proceeding. My rebuttal testimony also addresses criticisms of PacifiCorp's modeling assumptions and methodologies. My rebuttal demonstrates that:

- The updated economic analysis shows net customer benefits in all of the scenarios analyzed.
- The wind repowering project will produce present-value net customer benefits, based on updated economic analysis over the remaining life of the repowered wind facilities, ranging between $360 million to $635 million.

- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.38 billion and $1.65 billion, which compares to present-value project costs totaling $1.02 billion.
- These net and gross customer benefits are conservative, as they do not account for additional incremental energy output that will be generated with the installation of equipment that only recently has been verified to be available for repowering of certain wind facilities.
- When measured over a 20-year period, the present value of net customer benefits from wind repowering range between $90 million and $214 million, which does not account for the value of incremental energy output that will increase significantly beyond 2036.
- Project-by-project analysis, developed in response to criticisms raised by certain parties, confirms that the proposed scope of the project, including just over 999 megawatts ("MW") of existing wind resource capacity, is appropriate and will maximize customer benefits.
- Tax-policy sensitivity analysis, also developed in response to criticisms raised by certain parties, confirms that net customer benefits persist even with potential changes in the corporate federal income tax rate.
- The modeling tools and methodologies used to develop the economic analysis supporting the wind repowering project are robust.
- The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power

costs, and deliver substantial federal production tax credit ("PTC") benefits that will be passed on to customers. The proposed wind repowering project is in the public interest.

MODELING UPDATES

Q. Did PacifiCorp update its economic analysis supporting the wind repowering project?

A. Yes. The economic analysis was updated to correct certain model inputs and to reflect more current assumptions.

Q. Please summarize these updates.

A. The models were updated to: (1) implement a correction to certain transmission assumptions; (2) reflect more current load-forecast assumptions; (3) reflect more current forward-price-curve assumptions; and (4) to reflect more current cost-and-performance assumptions for the repowered wind facilities.

Q. Did you calculate how these updates impact the economic analysis that you summarized in your direct testimony?

A. Yes. PacifiCorp used the System Optimizer ("SO") model and the Planning and Risk model ("PaR") to determine the impact of these modeling updates on the economic analysis summarized in my direct testimony. These models were used to calculate how the present-value revenue requirement differential ("PVRR(d)") between a simulation with and without the wind repowering project changes after applying the modeling updates. The PVRR(d) calculated from the change in nominal revenue requirement due to wind repowering through 2050 was also calculated.

Q. What is the impact of these assumption changes in the economic analysis assuming medium natural gas prices and medium carbon dioxide ("CO_2") prices?

A. Based on SO model results through 2036, the expected wind repowering PVRR(d) benefits increase by $116.6 million, from $21.7 million as summarized in my direct testimony (Link Direct, Table 2) to $138.3 million. Based on stochastic-mean PaR results through 2036, the wind repowering PVRR(d) benefits increase by $101.8 million, from $13.5 million (Link Direct, Table 2) to $115.2 million. Based nominal revenue requirement results through 2050, the PVRR(d) benefits of wind repowering increase by $112.5 million, from $358.7 million (Link Direct, Table 3) to $471.2 million. I describe each of these modeling updates in more detail below.

Q. Please describe the correction to transmission assumptions applied in the updated economic analysis.

A. In my direct testimony, I described how PacifiCorp modeled de-rates to its Wyoming 230-kV transmission system (Link Direct, lines 344 - 359). Based on historical outage data, the transfer capability from eastern Wyoming to the Aeolus area was reduced by 36.5 MW in simulations that included the wind repowering project. This same de-rate was inadvertently not applied to the simulations that excluded the wind repowering project. This was corrected by applying the 36.5 MW transmission de-rate to simulations both with and without the wind repowering project.

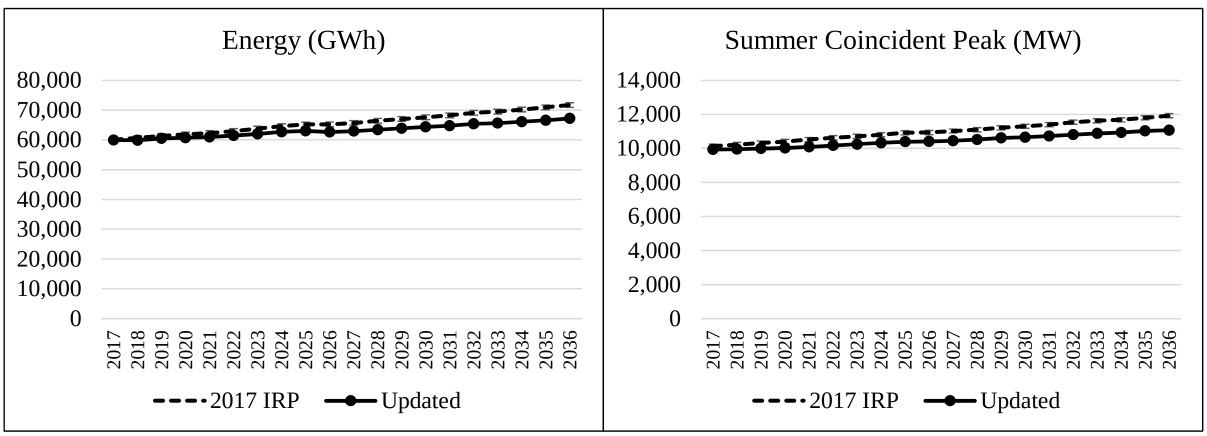
Q. Please describe the new load forecast assumptions included in the updated economic analysis.

A. The load forecast used in the economic analysis summarized in my direct testimony is the same load forecast used in PacifiCorp's 2017 Integrated Resource Plan ("IRP").

This 2017 IRP load forecast was finalized in December 2016. My updated analysis uses the Company's new load forecast completed in the summer of 2017, after the Company made its initial filing.

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

Figure 1. Comparison of the 2017 IRP and Updated Load Forecast Assumption



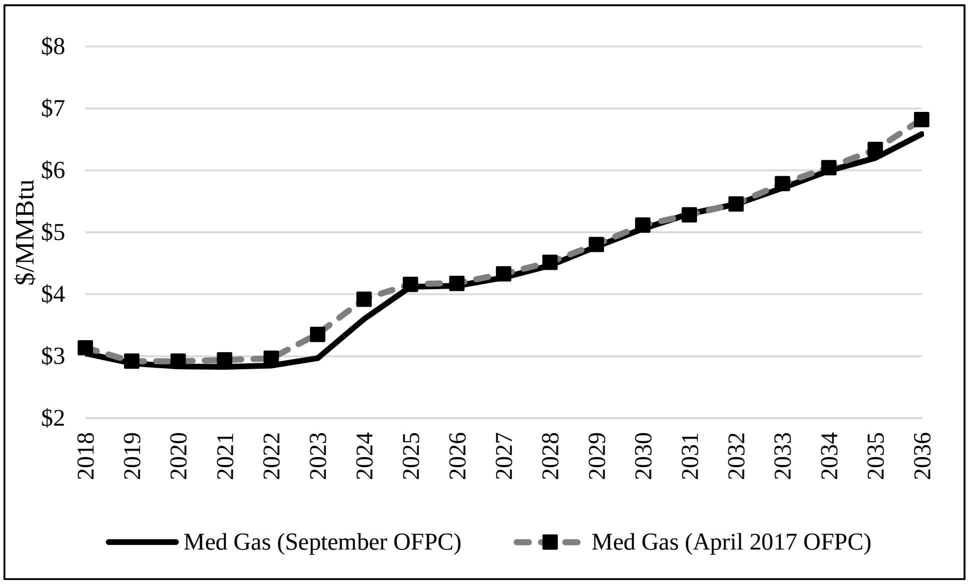
Changes in the load forecast are primarily driven by: (1) a reduction in Utah and Wyoming industrial loads principally due to reduced usage projections for a number of large customers; (2) increases in the growth of customer generation from 2017 to 2018, contributing to reductions in Utah residential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

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

A. In my direct testimony, I described nine price-policy scenarios, developed by pairing three natural-gas price forecasts (low, medium, and high) with three CO_2 price forecasts (zero, medium, and high). (Link Direct, lines 515 - 572.) The medium natural-gas price assumptions are derived from PacifiCorp's official forward price curve ("OFPC"). In the economic analysis summarized in my direct testimony, PacifiCorp used its April 26, 2017 OFPC.

PacifiCorp's most recent OFPC is dated September 30, 2017, which reflects more current market forwards and an updated forecast from [redacted]. Figure 2 compares Henry Hub natural-gas prices from the April 26, 2017 OFPC, as used to support the economic analysis in my direct testimony, with Henry Hub natural-gas prices from the updated September 30, 2017 OFPC. Over the period 2018 through 2036, the nominal levelized price for Henry Hub natural-gas prices has dropped by approximately 2.6 percent from $4.07/MMBtu to $3.97/MMBtu. The reduction in levelized prices is primarily driven by reductions in the 2023 to 2024 time frame.

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



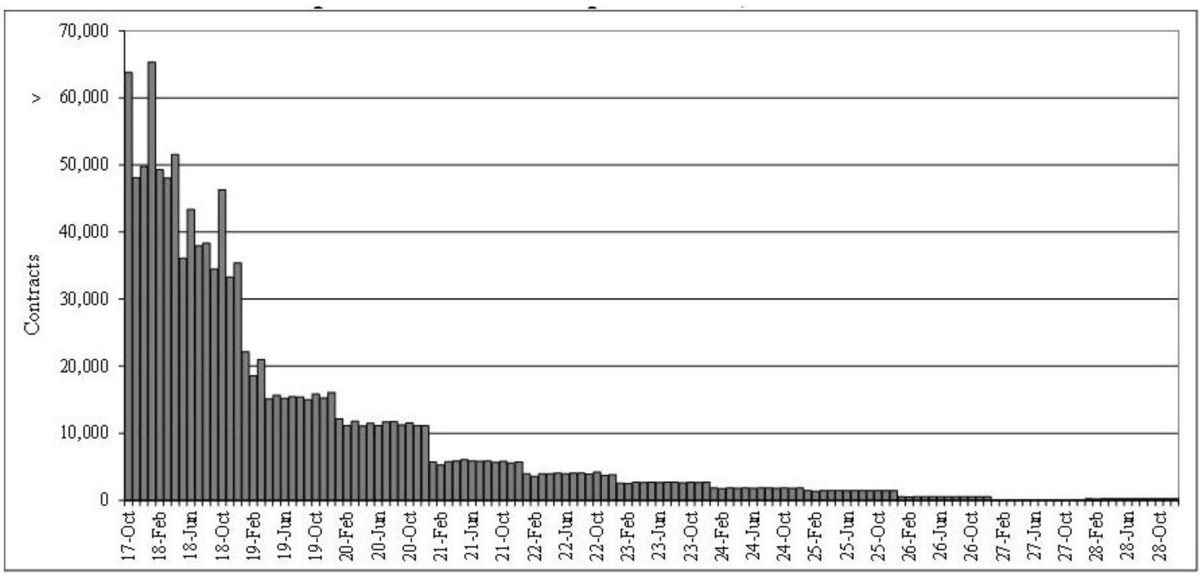
The updated OFPC reflects market forwards as of September 30, 2017, through October 2023. Prices in the updated market fundamentals forecast from [redacted], which are used exclusively in the OFPC beyond October 2024, track closely with those assumed in the April 2017 OFPC. PacifiCorp continues to blend market forwards from month 61 (November 2022) through month 72 (October 2023) with the fundamentals-based forecast from month 85 (November 2024) through month 96 (October 2025) to establish prices in month 73 (November 2023) through month 84 (October 2024).

Q. Mr. Peaco compares the Company's natural-gas price forecasts with NYMEX Henry Hub natural-gas futures through 2029 as of September 11, 2017, and concludes that this comparison demonstrates current market expectations most closely align with the Company's low natural-gas forecast. (Peaco Direct, lines 585 - 598.) How do you respond?

A. Mr. Peaco's conclusion is misguided because it relies solely on NYMEX Henry Hub natural-gas futures after 2022, which do not accurately capture market expectations for long-term natural-gas prices. Mr. Peaco fails to consider the open interest in NYMEX Henry Hub futures contracts, which quickly falls for futures contracts further out in time. The sparsity of open interest in the out period makes these futures contracts an unreliable indicator of market expectations for long-term natural-gas prices.

Each futures trade represents the creation of a new contract and is indicative of new capital being committed to the market. Figure 3 shows NYMEX Henry Hub natural-gas open interest as of September 11, 2017—the same quote date used by Mr. Peaco to compare NYMEX futures prices to the Company's Henry Hub natural-gas price forecast.

Figure 3. NYMEX Henry Hub Natural Gas Futures
Open Interest as of September 11, 2017



This figure shows that open interest is greater in the near term and significantly lower in the long term. For instance, in 2018 open contracts average over 43,200. By 2023, open contracts average just over 2,600—approximately six percent of the open interest observed for 2018 contracts. The concentration in the earlier futures indicates the market is deeper and stronger in the near term because fewer market participants are willing to commit capital required to enter and maintain long-term contracts.

There are very few contracts supporting NYMEX Henry Hub natural-gas-futures prices over the period in which Mr. Peaco claims the market outlook most closely aligns with the Company's low natural-gas price forecast (*i.e.*, beyond 2022). Contracts with greater open interest more accurately represent a market consensus of where spot prices are likely to trade. Long-term prices are shaped by a handful of participants who are lightly committed. These participants are basing their decisions on highly imperfect data. Short-term prices are shaped by a large field of market participants, who commit far more capital because there is more transparency around the conditions and variables that can impact prices.

Q. Did PacifiCorp update the low and high natural-gas price scenarios used in the economic analysis presented in your direct testimony?

A. No. Current low and high natural-gas price scenarios produced by third-party forecasters are not materially different than those used to support the economic analysis in my direct testimony. Similarly, there are no material changes in third-party forecasts for CO_2 price assumptions. Consequently, the low and high natural-gas price assumptions and the medium and high CO_2 price assumptions used in the economic analysis summarized in my direct testimony remain valid for testing how these variables impact the overall economics of the wind repowering project.

Q. Please describe the updated cost-and-performance assumptions for the repowered wind facilities.

A. As described in the rebuttal testimony of Company witness Mr. Timothy J. Hemstreet, General Electric ("GE") finished developing a 91-meter rotor for use in repowering wind facilities and has completed engineering and design review on a [redacted] turbine. Assuming the repowered wind facilities continue to operate within the limits specified in their large-generator interconnection agreements ("LGIAs"), the updated expected incremental energy output from wind repowering, accounting for use of the [redacted] turbines on GE sites (all but Marengo 1, Marengo 2, and Goodnoe Hills), is 25.9 percent (743 GWh per year)—up from the 19.2 percent (551 GWh per year) increase assumed in my original economic analysis. Mr. Hemstreet also explains that the Company has fixed pricing for the wind repowering turbines supporting updated capital costs. The updated total up-front capital investment is $1.083 billion—a $45 million reduction from the cost assumed in my original economic analysis.

As noted by Mr. Hemstreet, the Company did not receive verification that the [redacted] turbine was technically suitable for GE sites within the scope of the repowering project until October 6, 2017. At this time, the Company had already begun updating its analysis assuming the use of a [redacted] turbine at GE sites. The longer blade length also improves expected incremental annual energy output relative to the [redacted] turbine equipment assumed in my original analysis. Assuming use of the [redacted] turbines, the updated incremental energy output is 24.9 percent (714 GWh per year)—up from the 19.2 percent (551 GWh per year) increase assumed in my original economic analysis. The updated total up-front capital investment assuming the use of [redacted] turbines on GE sites is $1.083 billion—identical to the up-front capital investment required assuming the use of [redacted] turbines on GE sites.

Because the Company did not receive verification that the [redacted] turbine was technically suitable for GE sites until after the updated economic analysis had been initiated, the bulk of my updated economic analysis assumes the use of [redacted] turbines on GE sites. However, now that the Company has received verification that the [redacted] turbines can be deployed on GE sites, I summarize the results of a sensitivity study that quantifies the incremental benefits from the use of this equipment later in my rebuttal testimony.

UPDATED SYSTEM-MODELING PRICE-POLICY RESULTS

Q. Did PacifiCorp update its system modeling among different price-policy scenarios to reflect the modeling updates described above?

A. Yes. Using the same system methodology described in my direct testimony, PacifiCorp updated the economic analysis for the wind repowering project, incorporating the modeling updates described earlier in my rebuttal testimony, including the assumed use of [redacted] turbines on GE sites. This updated analysis was performed using the SO model and PaR among nine different price-policy scenarios.

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

A. Table 1 summarizes the updated PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-R2).

Table 1. Updated SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($110)	($90)	($95)
Low Gas, Medium CO_2	($125)	($108)	($113)
Low Gas, High CO_2	($133)	($114)	($119)
Medium Gas, Zero CO_2	($137)	($116)	($122)
Medium Gas, Medium	($138)	($115)	($121)
Medium Gas, High CO_2	($157)	($131)	($137)
High Gas, Zero CO_2	($196)	($152)	($160)
High Gas, Medium CO_2	($204)	($167)	($175)
High Gas, High CO_2	($214)	($167)	($176)

Over a 20-year period, before accounting for the increase in incremental energy output beyond 2036, the wind repowering project reduces customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits range between $115 million, when derived from PaR stochastic-mean results, and $138 million, when derived from SO model results.

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

A. Projected system costs increase with high natural-gas price assumptions, and similarly, increase with high CO_2 price assumptions. Conversely, system costs decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Generally, this same trend applies when looking at the change in system costs between simulations with and without wind repowering. There are, however, a few exceptions. For example, in the medium natural-gas price scenarios where a change from a zero CO_2 price assumption to a medium CO_2 price assumption has a very marginal impact on the PVRR(d) benefits from repowering. In this price-policy scenario, the increase to system costs from PaR caused by the introduction of a CO_2 price assumption is slightly greater in the simulation without wind repowering than it is in the simulation with wind repowering.

These slight variations from expected trends can be explained by the difference in functionality between the SO model and PaR. Relative to the SO model, PaR provides additional granularity on how wind repowering is projected to affect system operations. However, in its optimization to minimize system costs, PaR cannot modify the resource portfolio, which is based on SO model results. This can contribute to variation in the trends observed between the two models as price-policy assumptions change across the scenarios. Importantly, both models, each having its own strengths, show that the wind repowering benefits are robust across a range of price-policy assumptions.

Q. Mr. Peaco claims that the Company's modeling has "methodological issues" because the results have "several anomalies," e.g., the benefits do not increase in every scenario where the gas price increases. (Peaco Direct, line 375-390.) Please respond.

A. As I just discussed, the impact of natural-gas price and CO_2 price assumptions follows the expected trends in the simulations with and without wind repowering that are used to calculate the PVRR(d) results for each price-policy scenario. In some instances, the relative impact of natural-gas price and CO_2 price assumption changes can be greater on the simulation with repowering or greater on the simulation without repowering. Any perceived anomalies in the PVRR(d) results among price-policy scenarios can be explained by examining the model results for each of these simulations in detail, and accounting for changes to resource mix and system dispatch.

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

A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 1 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Accounting for the updated performance assuming use of [redacted] turbines on GE sites, customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2036 (up from $4 million in my original analysis).

Q. OCS witness Ms. Ramas recommends that the Commission ignore any repowering benefit related to the possibility of future REC revenues (Ramos Direct, lines 668-691.) How do you respond?

A. PacifiCorp is not relying on potential incremental REC revenues in its economic analysis of the wind repowering project, as evidenced by the fact REC revenues are not included in the PVRR(d) results summarized in Table 1. While Ms. Ramas correctly notes that the REC market is illiquid and lacks transparency, PacifiCorp is active in this market and routinely engages in REC sales and purchases. Quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits of wind repowering *could* improve *if* the incremental RECs can be monetized in the market.

Q. Is there additional upside to these PVRR(d) results?

A. Yes. The PVRR(d) results in Table 1 assume that [redacted] turbines are deployed on GE sites, not the [redacted] turbines now secured for these sites, which will deliver additional incremental energy output without any increase in cost. As described later in my rebuttal testimony, sensitivity analysis developed off of the medium natural-gas price and medium CO_2 price scenario that assumes the use of the [redacted] turbines improves the PVRR(d) benefits of wind repowering by $11 million to $13 million if these facilities continue operating within the limits specified in their LGIAs. If the LGIAs are modified to accommodate additional energy output, the incremental benefits of wind repowering increase by between $37 million to $48 million.

UPDATED REVENUE REQUIREMENT MODELING PRICE-POLICY RESULTS

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

A. Yes. Using the same annual revenue requirement modeling methodology described in my direct testimony, PacifiCorp updated its forecast of the change in nominal annual revenue requirement due to the wind repowering project, incorporating the modeling updates described earlier my rebuttal testimony, including the assumed use of [redacted] turbines on GE sites.

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

A. Table 2 summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP__(RTL-R3).

Table 2. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($360)
Low Gas, Medium CO_2	($480)
Low Gas, High CO_2	($473)
Medium Gas, Zero CO_2	($483)
Medium Gas, Medium CO_2	($471)
Medium Gas, High CO_2	($534)
High Gas, Zero CO_2	($555)
High Gas, Medium CO_2	($635)
High Gas, High CO_2	($619)

When system costs and benefits from the wind repowering project are extended out through 2050, covering the full depreciable life of the repowered wind facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios. The PVRR(d) benefits range from $360 million in the low natural gas, zero CO_2 scenario to $635 million in the high natural gas, medium CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of wind repowering are $471 million.

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

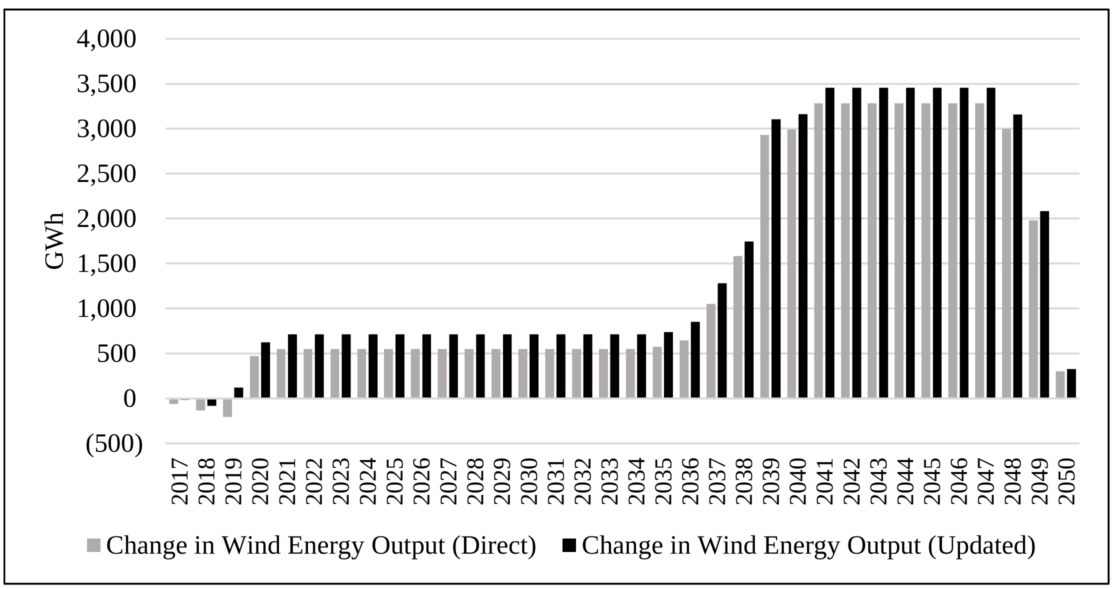
A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 2 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Accounting for the updated performance assuming use of [redacted] turbines on GE sites, customer benefits for all price-policy scenarios would improve by approximately $13 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2050 (up from $11 million in my original analysis). As noted earlier, quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits of wind repowering *could* improve *if* the incremental RECs can be monetized in the market.

Q. What causes the increase in PVRR(d) results when calculated off of the change in nominal revenue requirement through 2050 relative to the system modeling results calculated off of the change in system costs through 2036?

A. In my direct testimony, I explain that the extended analysis picks up the sizable increase in incremental wind energy output beyond the 20-year period analyzed with the SO model and PaR. (Link Direct, lines 675 - 694.) This same rationale applies to the economic analysis that has been refreshed to incorporate the modeling updates described earlier in my rebuttal testimony. In fact, with the increase in expected incremental energy output from the wind facilities, the change in incremental wind energy output is higher than what was assumed in the economic analysis summarized in my direct testimony.

Figure 4 shows the updated incremental change in wind energy output resulting from the repowering project alongside the same assumptions used in the economic analysis summarized in my direct testimony. The updated assumptions continue to show progressively higher levels of incremental energy output from 2036 through 2040, as wind facilities originally placed in service between 2006 and 2010 would have otherwise reached the end of their lives. Based on the updated assumptions, the average incremental increase in wind energy output is approximately 714 GWh. Beyond 2040, and before the new equipment reaches the end of its depreciable life, the average annual incremental increase in wind energy output is 3,454 GWh.

Figure 4. Comparison of the Updated Change in Incremental Wind Energy Output Due to Wind Repowering



Q. Mr. Hayet provides analysis showing that if the useful lives of the wind turbines are extended for an additional 10 years, then the benefits of repowering decrease. (Hayet Direct, lines 479-98.) Mr. Higgins and Mr. Peaco make similar points. (Higgins Direct, lines 158-171; Peaco Direct, lines 53-56.) How do you respond to this concern?

A. PacifiCorp's annual revenue requirement analysis, which extends the economic analysis beyond the 2036 time frame, captures the upside of increased incremental energy output beyond the period in which the repowered wind facilities would have otherwise reached the end of their depreciable lives. This analysis reasonably assumes that these facilities would be retired at the end of their current depreciable lives.

If one were to assume that the wind facilities would continue to operate for some period beyond their current depreciable lives if not repowered, it is reasonable to assume that the repowered wind facilities would also operate for some comparable period of time beyond their 30-year life initiated upon repowering.

The effect of this assumption would be to defer, but not eliminate, the value of the sizable increase in expected incremental energy beyond the assumed operable life of the wind facilities. Consequently, this would defer the associated incremental benefits beyond the assumed operable life of the wind facilities, which would be more heavily discounted in the present-value calculation. For this reason, it is no surprise that the PVRR(d) is reduced if one were to assume the existing wind facilities and the repowered wind facilities both continue to operate beyond their depreciable lives.

Mr. Hayet's analysis estimating the impact on the PVRR(d) results assuming the existing wind facilities, if not repowered, and the repowered wind facilities operate for 10 years beyond their depreciable life is presented over two different time frames—one where the PVRR(d) is calculated from annual data through 2060 and one where the PVRR(d) is calculated from annual data through 2050.

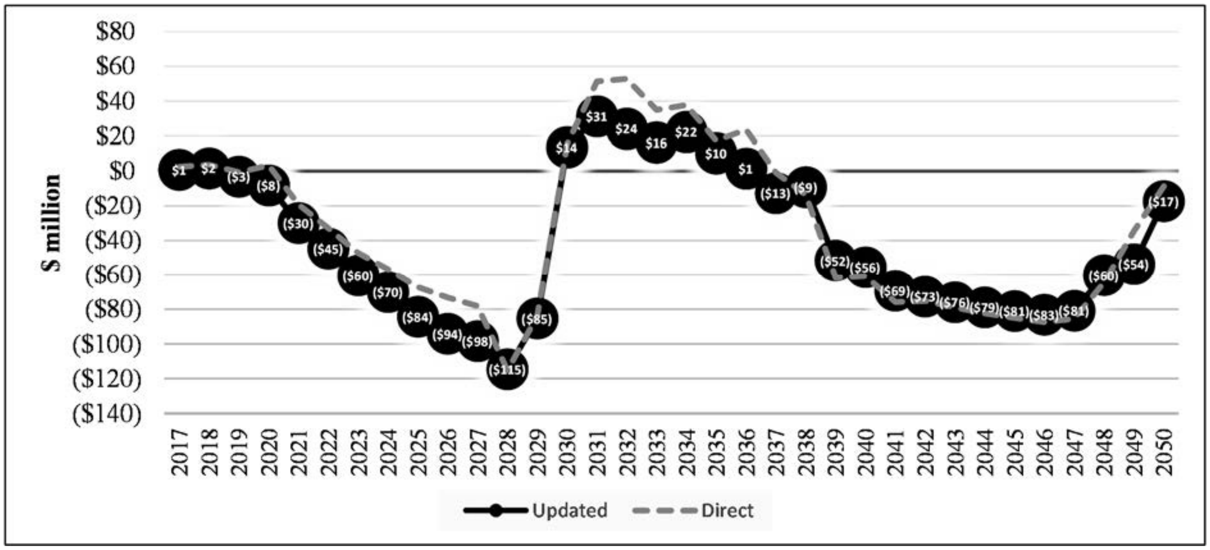
The results based on the PVRR(d) calculated from annual data through 2060 are directionally consistent with the expectations I describe above. Mr Hayet's analysis shows that benefits are reduced, but importantly, this analysis shows that the wind repowering project still has sizable economic benefits in eight out of nine price-policy scenarios. Moreover, Mr. Hayet's analysis was performed without accounting for the modeling updates described earlier in my rebuttal testimony, which significantly increase the expected benefits of the wind repowering project.

Mr. Hayet's results calculated from annual data through 2050 are misleading and should be dismissed. By assuming a 10-year extension to the operable life and truncating the present-value calculation to eliminate the last 10 years of the assumed asset lives, this analysis erroneously eliminates the sizable increase in incremental energy from the repowered wind facilities from 2051 through 2060.

Q. Please describe the change in annual nominal revenue requirement from the wind repowering project.

A. Figure 5 shows the updated change in nominal revenue requirement due to wind repowering for the medium natural gas, medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects updated project costs, including capital revenue requirement (i.e., depreciation, return, income taxes, and property taxes), operations and maintenance expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from wind repowering, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the wind repowering project.

Figure 5. Updated Total-System Annual Revenue Requirement With Wind Repowering ($ million)



This figure has the same basic profile as Figure 5 from my direct testimony. This profile shows substantial near-term benefits associated with the PTCs, a period over which the change in annual revenue requirement increases after the PTCs expire, and a period over the long term where the change in annual revenue requirement is reduced based on substantial and progressively growing increases to incremental energy output between 2036 through 2041. The PVRR(d) benefits from the wind repowering project calculated off of this stream of data is $471 million—the same figure shown in Table 2 for the medium natural gas, medium CO_2 price-policy scenario.

Q. Did parties in this proceeding raise concerns with the methodology used in PacifiCorp's economic analysis to calculate customer benefits from 2037 through 2050?

A. Yes. Mr. Hayet claims that the extended results to 2050 are questionable and that customers would have to wait 20 years before significant benefits could be achieved. (Hayet Direct, lines 269-272.) Similarly, Mr. Peaco criticizes the extrapolation methodology, stating that extrapolation of results beyond 2036 is problematic. (Peaco Direct, lines 539-540.)

Q. How do you respond?

A. As described in my direct testimony, the methodology used to extrapolate system benefits from wind repowering from 2037 through 2050 is based on the aggregate system benefits derived from the SO model and PaR over the period 2028 through 2036. (Link Direct, lines 455 - 501.) These data, based on how the wind repowering project affects forecasted system costs, are a reasonable proxy for projected long-term benefits associated with the wind repowering project.

Regardless of the methodology used to extrapolate the system benefits of wind repowering to 2050, the point of extrapolating results is to capture the benefits from the significant increase in the expected annual energy output from the repowered wind facilities beyond the period in which the existing wind facilities would have otherwise hit the end of their lives. While the methodology used in my analysis is valid, the value of this incremental energy can be evaluated in different ways.

Table 3 summarizes how the PVRR(d) results through 2050 would change if flat market prices at the Palo Verde ("PV") market from the September OFPC were used as the basis to evaluate the value of incremental energy from wind repowering over the 2037 to 2050 time frame. Recognizing there is both upside and downside price risk to the value of this energy, I assume different levels of PV prices—70 percent of the PV forward curve, 100 percent of the PV forward curve, and 130 percent of the PV forward curve. PacifiCorp's September OFPC includes forward prices through 2042. Conservatively, I assume no escalation in PV prices beyond 2042 for each of these scenarios. I also calculate the PVRR(d) through 2050 assuming the incremental energy from the project from 2037 through 2050 is worth nothing. Each of these scenarios is shown alongside the $471 million PVRR(d) benefit when incremental energy from repowering beyond 2036 is calculated from system modeling results over the 2028 through 2036 time frame.

Table 3. Long-Term Benefit Sensitivity

Source of 2037-2050 Benefits	**Nominal Levelized Benefit from 2037 – 2050 ($/MWh)**	**Annual Revenue Requirement PVRR(d) (Benefit)/Cost ($ million)**
2028-2036 System Modeling	$57.82	($471)
70% of PV Flat OFPC	$45.30	($385)
100% of PV Flat OFPC	$64.71	($522)
130% of PV Flat OFPC	$84.12	($658)
No Value	$0.00	($66)

This analysis demonstrates that regardless of the methodology used to extend wind repowering benefits to 2050, the PVRR(d) result shows significant customer savings in all scenarios. If the incremental energy is valued at the PV forward curve, the PVRR(d) benefits of repowering are $522 million, which is $51 million higher than the methodology used in my analysis. Even if the incremental energy beyond 2036 is assumed to have no value at all, which is an unimaginable scenario, the wind repowering project delivers $66 million in PVRR(d) benefits.

Q. Mr. Peaco argues that the Company's extrapolation method for the extended period is unreasonable because of the year-to-year volatility in system costs from 2028 to 2036. (Peaco Direct, lines 494-510.) Is this a fair criticism of the extrapolation?

A. No. Mr. Peaco's assessment of the volatility in system modeling benefits is misguided because he focuses solely on changes to system *fixed* costs between simulations with and without repowering and ignores contemporaneous changes to system *variable* costs. When the SO model identifies a least-cost resource portfolio, it evaluates all fixed and variable system costs to arrive at an optimized least-cost solution—it does not separately optimize system fixed costs nor does it separately optimize system variable costs. It is not uncommon for there to be volatility in system fixed costs as resources in the portfolio change in response to changes in input assumptions (*i.e.*, when wind repowering is factored in the SO model's determination of the optimal resource mix). Generally, there are offsetting changes to system variable costs that coincide with spikes or dips in the change to system fixed costs between two simulations. Mr. Peaco's observations of model results is explained by not considering changes to all of the system costs (fixed and variable costs) between simulations with and without wind repowering and do not indicate that there are model errors or model limitations.

Mr. Peaco further observed that the SO model evaluates resource alternatives as discrete choices. (Peaco Direct, lines 475-477.) This observation is correct. For instance, the SO model is not configured to be able to choose a percentage of a new combined cycle unit (for example, the model cannot choose to add a two MW combined cycle plant), because this is unrealistic. This does not mean that the model is not well-suited to analyze benefits from the wind repowering project. In fact, it is critical to understand how the wind repowering project might influence projected system costs that account for discrete changes in the resource portfolio.

Q. Both Mr. Peaco and Mr. Hayet argue that the expected customer benefits are modest relative to the overall project costs and that there is very little certainty that customers will see significant, if any, cost savings. (Peaco Direct, lines 227 - 234; Hayet Direct, lines 263 - 274.) Is this a fair criticism?

A. No. Mr. Peaco and Mr. Hayet both mischaracterize the relationship between the cost and benefits of the wind repowering project by comparing the up-front investment cost to the *net* benefits of the project. This artificially makes it appear that customer benefits are relatively small in relation to the investment required to deliver those benefits, when in fact, the gross benefits from the project are actually greater than total project costs.

For instance, in the updated economic analysis, the PVRR(d) results calculated from the change in system costs through 2050 assuming medium natural gas and medium CO_2 prices show a $471 million net customer benefit from wind repowering. This is based on present-value project costs, including changes to run-rate operating costs, totaling $1.02 billion. The present value of customer benefits, including federal PTC benefits, for this price-policy scenario is $1.49 billion, which is $472 million greater than the present value of project costs. In fact, the present value of customer benefits among all nine price-policy scenarios ranges between $1.38 billion and $1.65

billion. In all scenarios, the present value of customer benefits far exceed the present value of customer costs.

PROJECT-BY-PROJECT ANALYSIS

Q. Did parties in this proceeding raise concerns with the scope of the proposed wind repowering project?

A. Yes. OCS witness Mr. Hayet faults PacifiCorp for modeling repowering as a single, all-or-nothing project, instead of modeling each facility individually, and claims that some of the individual wind facilities are not economic. (Hayet Direct, lines 295-308, 389-390.) DPU witness Mr. Peaco similarly criticizes PacifiCorp's modeling for not performing a project-by-project assessment. (Peaco Direct, lines 258-272.)

Q. Is Mr. Hayet correct that some of the individual facilities are not economic to repower?

A. No. Mr. Hayet attempts to calculate the PVRR(d) for each wind facility, but does so incorrectly. He first calculates the net levelized cost of each facility by netting the PTC benefits against the capital and run-rate operating cost of each facility. This part of his calculation is reasonable. Mr. Hayet then allocates PacifiCorp's forecast of system benefits, having a present value of approximately $150 million, to each wind facility based on its share of the total incremental wind energy output expected after repowering. This allocation methodology is not appropriate.

Resource-portfolio and system-benefit results from the full scope of the wind repowering project reflect system interactions that cannot be reasonably allocated to individual wind facilities. Consequently, a spreadsheet analysis that begins with aggregate system optimization results that attempts to back into individual resource contributions neglects to consider how these wind facilities interact within the broader system and will therefore yield arbitrary results.

In response to the concerns raised by Messrs. Hayet and Peaco, PacifiCorp developed a series of studies using the SO model and PaR to analyze the net benefits of each individual wind facility included in the proposed scope of the wind repowering project. This is a more robust analytical approach that accounts for how each repowered wind facility interacts with the broader system.

Q. Please describe how you developed this project-by-project analysis.

A. The methodology used to develop the project-by-project analysis is similar to the methodology used to perform the economic analysis for the proposed wind repowering project. Assuming medium natural gas and medium CO_2 price-policy assumptions, PacifiCorp ran two SO model simulations for each of the 12 wind facilities within the scope of the proposed wind repowering project—one simulation in which all 12 facilities within the proposed scope are repowered and one simulation that assumes one of the 12 wind facilities is not repowered. For each simulation, the difference in projected system costs from the SO model, accounting for any changes to the resource mix over a 20-year forecast period, are used to calculate the marginal PVRR(d) for each wind facility.

Using the resource portfolios from the SO model simulations, this same approach was used to calculate PVRR(d) for each wind facility using projected system costs from PaR over a 20-year forecast period. Finally, the SO model and PaR model results are used to estimate the change in nominal annual revenue requirement for each wind facility by extending the system modeling results to 2050. The methodology used to estimate the change in nominal annual revenue requirement through 2050 is identical to the methodology used to analyze the full scope of the wind repowering project.

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

A. Table 4 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and for PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering.

Table 4. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($17)	($14)	($14)
Glenrock 3	($5)	($3)	($4)
Seven Mile Hill 1	($23)	($20)	($21)
Seven Mile Hill 2	($5)	($5)	($5)
High Plains	($4)	($1)	($1)
McFadden Ridge	($1)	($0.20)	($0.20)
Dunlap Ranch	($14)	($11)	($11)
Rolling Hills	($5)	($3)	($3)
Leaning Juniper	($3)	($3)	($4)
Marengo 1	($28)	($26)	($27)
Marengo 2	($10)	($9)	($10)
Goodnoe Hills	($21)	($21)	($22)
Total	($138)	($117)	($122)

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

A. Table 5 summarizes the PVRR(d) results for each wind facility calculated off of the change in annual nominal revenue requirement through 2050. Unlike the results summarized in Table 4, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering.

Table 5. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Annual Revenue Requirement PVRR(d)
Glenrock 1	($50)
Glenrock 3	($15)
Seven Mile Hill 1	($65)
Seven Mile Hill 2	($17)
High Plains	($37)
McFadden Ridge	($11)
Dunlap Ranch	($60)
Rolling Hills	($30)
Leaning Juniper	($34)
Marengo 1	($77)
Marengo 2	($30)
Goodnoe Hills	($50)
Total	($477)

Q. Why is the sum of the project-by-project PVRR(d) results summarized in Tables 4 and 5 not precisely equal to the comparable scenario results shown in Tables 1 and 2 of your rebuttal testimony?

A. The scope of the wind repowering project is similar, yet unique, for each of the studies summarized in these tables. Eliminating one of the wind facilities from the scope of repowering project affects how the remaining repowered facilities contribute to the forecasted system costs and benefits of repowering. The impact on system costs that results from altering the scope of the repowering project varies depending upon the specific characteristics of the wind facility being studied. For this reason, it is reasonable to expect that the sum of the project-by-project results in Tables 4 and 5 are not precisely equal to the comparable scenario results in Tables 1 and 2.

Q. The project-by-project results vary by wind facility, and some wind facilities appear to show relatively small PVRR(d) benefits. Do these results support eliminating those or any other facility from the scope of the wind repowering project?

A. No. The magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows an $11 million benefit when repowered—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is 14 percent of the $77 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, current capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the current capacity for Marengo 1 (140.4 MW). Similarly, the expected energy output after repowering for McFadden Ridge (approximately 108 GWh per year) is approximately 22 percent of the expected energy output after repowering for Marengo 1 (approximately 408 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental MWh expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 6 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. The table shows the Seven Mile Hill 2 facility produces the largest net benefit per incremental MWh and Leaning Juniper produces the smallest net benefit per incremental MWh. All facilities produce net benefits equal to or greater than $27/MWh of incremental energy output after repowering.

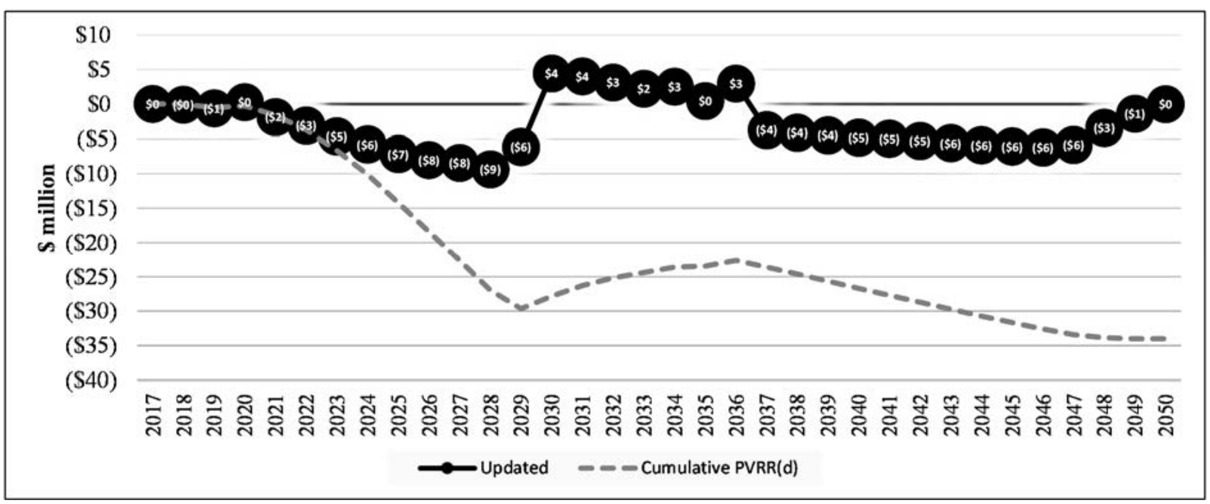
Table 6. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh)

Wind Facility	Nominal Levelized Net Benefit
Glenrock 1	$43/MWh
Glenrock 3	$39/MWh
Seven Mile Hill 1	$46/MWh
Seven Mile Hill 2	$58/MWh
High Plains	$29/MWh
McFadden Ridge	$28/MWh
Dunlap Ranch	$42/MWh
Rolling Hills	$36/MWh
Leaning Juniper	$27/MWh
Marengo 1	$37/MWh
Marengo 2	$31/MWh
Goodnoe Hills	$47/MWh

Q. Have you reviewed the change in annual nominal revenue requirement due to wind repowering from the Leaning Juniper facility, which yields the lowest net benefits per MWh of incremental energy output among all facilities within the proposed scope of repowering project?

A. Yes. Figure 6 shows the change in nominal revenue requirement due to wind repowering for the Leaning Juniper wind facility. The figure also shows the cumulative PVRR(d) for Leaning Juniper through 2050. The cumulative PVRR(d) for any given year reflects the present value net benefits from prior years that are associated with repowering Leaning Juniper. For instance, the cumulative PVRR(d) shown for 2020 represents the present value of the net benefits for repowering over the period 2017 through 2020. Consequently, the cumulative PVRR(d) in 2050 captures the net benefits of repowering the Leaning Juniper wind facility through its expected useful life (*i.e.*, $34 million of net benefit as reported in Table 5).

Figure 6. Total-System Annual Revenue Requirement for Leaning Juniper with Wind Repowering ($ million)



As is the case with the projected change in nominal revenue requirement for the all projects in the wind repowering scope presented in Figure 5, this figure shows that repowering Leaning Juniper will produce substantial near-term customer benefits, followed by a period in which the change in annual revenue requirement exhibits a moderate increase after the PTCs expire. In 2037 and beyond, the change in annual revenue requirement is reduced due to the substantial increase in incremental energy output beyond the period in which Leaning Juniper would have otherwise reached the end of its useful life (*i.e.*, increasing from approximately 70 GWh before 2037 to just under 304 GWh beyond 2037).

Importantly, with the substantial cost savings associated with the PTCs over the first 10 years after repowering, the cumulative PVRR(d) reaches $30 million by 2029—approximately 87 percent of the PVRR(d) benefits calculated off the change in nominal system costs through 2050. The cumulative PVRR(d) benefits decline after the PTCs expire, but when Leaning Juniper would have otherwise reached the end of its useful life in 2036, wind repowering still yields cumulative PVRR(d) benefits totaling $23 million. Even if one were to assume that there is *no* net incremental benefit associated with the incremental energy output expected from Leaning Juniper beyond 2036, the net benefits of repowering this facility, which yields the lowest nominal levelized net benefit per MWh of incremental energy among all of the wind facilities within the scope of the repowering project, would still generate net customer benefits totaling $23 million on a present-value basis.

Q. What do you conclude from this project-by-project analysis?

A. The project-by-project analysis demonstrates that the proposed scope of the wind repowering project, which includes repowering 12 wind facilities with a current capacity totaling just over 999 MW is appropriate and will maximize customer benefits.

This is a conservative analysis because the project-by-project analysis evaluates the GE projects using lower generation output from [redacted] turbines, not the higher output expected from the [redacted] turbines the Company has now secured.

TAX POLICY SENSITIVITY

Q. Several witnesses argue that the economic value of the repowering project may be adversely impacted if the federal corporate income tax decreases. (Mangelson Direct, lines 31 - 33; Hayet Direct, 49 - 50; Ramas Direct, 570 - 572; Higgins Direct 315 - 316.) Please respond.

A. The potential changes, if any, to the federal corporate income tax rate are highly uncertain. For this reason, I did not include a sensitivity in my original analysis to account for speculative tax rate changes. While this issue remains uncertain, to respond to the parties' concerns, I have performed a sensitivity analysis that assumes a lower federal corporate tax rate to determine how that lower rate impacts the economic benefits from the wind repowering project.

Q. Please describe the corporate tax rate assumption used for this sensitivity analysis.

A. For purposes of the tax policy sensitivity, PacifiCorp assumes the current federal income tax rate is decreased from 35 percent to 25 percent. The basis for this assumed reduction is provided in the rebuttal testimony of Company witness Ms. Nikki L. Kobliha. Assuming a marginal state income tax rate of 4.54 percent less a federal deductibility benefit of 1.135 percent, the assumed net state tax rate is 3.405 percent. Based on these inputs, the effective combined federal and state income tax rate assumed for this sensitivity is 28.405 percent.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and PaR for this sensitivity.

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital ("post-tax WACC"), which is used as the discount rate in the SO model and PaR. Assuming no change to the corporate tax rate, the discount rate assumed in the benchmark economic analysis is 6.57 percent. Assuming a drop in effective combined federal income tax rate from 37.951 percent to 28.405 percent for purposes of this sensitivity increases the discount rate to 6.81 percent. This modified discount rate assumption is used in both the SO model and PaR for each simulation of PacifiCorp's system—simulations with and without wind repowering.

The modified income tax rate assumed for this sensitivity also affects the capital revenue requirement for all new resource options available for selection in the SO model. As described in my direct testimony, capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. (Link Direct, lines 412-431). This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for a specific types of assets, are differentiated by each asset's assumed life, book depreciation rates, and tax depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were updated for each simulation of PacifiCorp's system—simulations with and without wind repowering.

Finally, the modified income tax rate assumption affects the tax gross-up of all PTC-eligible resources. As noted in my direct testimony, the current value of federal PTCs is $24/MWh, which equates to a $38.68/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 37.95 percent. (Link Direct, lines 99-102). If the effective combined federal and state income tax rate were reduced to 28.405 percent, the reduction in revenue requirement associated with federal PTCs would drop from $38.68/MWh to $33.52/MWh, adjusted for inflation over time. The impact of the modified income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model in the simulations with and without wind repowering. The adjustment to the reduction in revenue requirement associated with federal PTCs was also applied to repowered wind facilities in the simulation with repowering.

Q. Please summarize the results of the tax policy sensitivity.

A. Table 7 summarizes the results of the sensitivity that assumes the corporate federal income tax rate is reduced from 35 percent to 25 percent. To assess the potential impact of a change in the federal corporate tax rate, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the comparable benchmark study in which it is assumed the federal corporate income tax rate is not changed. The sensitivity results reflect medium natural gas and medium CO_2 price-policy assumptions.

Table 7. Tax Policy Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($45)	($138)	$93
PaR Stochastic Mean	($23)	($115)	$93
PaR Risk Adjusted	($24)	($121)	$97

Q. What do you conclude from the tax policy sensitivity results?

A. Although the overall benefit of the wind repowering project is reduced by between $93 million to $97 million, the wind repowering project still produces net economic benefits for customers.

Q. Messrs. Peaco and Hayet suggest that if the federal corporate income tax rate were reduced to 15 percent, the repowering project may be uneconomic. (Peaco Direct, lines 766 - 767; Hayet Direct, lines 369 -370.) Is their assumption reasonable?

A. No. As described in Ms. Kobliha's rebuttal testimony, any reduction to the corporate federal income tax rate remains speculative at this point. Given the many potential impediments to any such change, it is unreasonable to assume that the federal income tax rate will decrease to 15 percent, a reduction of more than 50 percent from current levels.

PROJECT EQUIPMENT SENSITIVITY

Q. Did you perform a sensitivity study to evaluate the upside benefits of the wind repowering project assuming use of the [redacted] turbines on repowering sites that will use GE equipment?

A. Yes. As described earlier in my rebuttal testimony, after initiating the updated analysis assuming use of [redacted] turbines, PacifiCorp received verification that the [redacted] turbines are technically feasible for wind repowering at wind repowering sites that will use GE equipment. Assuming repowered wind facilities continue to operate within the limits of their LGIAs, this will increase incremental annual energy output for the wind repowering project by 25.9 percent (743 GWh per year)—up from the 24.9 percent (714 GWh per year) assumed in my updated economic analysis. This equipment can be deployed without any incremental cost.

Q. Please summarize the results of this sensitivity.

A. Table 8 summarizes the results of the sensitivity that assumes [redacted] turbines are deployed on wind repowering sites that will use GE equipment. To assess the potential impact of deploying this equipment, the PVRR(d) was calculated through 2036 based on the SO model and PaR, and these results are presented alongside the comparable benchmark study which assumed use of [redacted] turbines. The sensitivity reflects medium natural gas and medium CO_2 price-policy assumptions and shows that the benefits of deploying the [redacted] turbines range between $11 million to $13 million before accounting for the sizable increase to incremental energy output from the repowered wind projects beyond 2036.

Table 8. LGIA-Limited Equipment Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($152)	($138)	($13)
PaR Stochastic Mean	($127)	($115)	($11)
PaR Risk Adjusted	($132)	($121)	($11)

Q. Did you also analyze the upside benefits based on the [redacted] turbines assuming the LGIAs for the repowered wind facilities can be modified to accommodate additional output from the wind repowering project?

A. Yes. If the LGIAs can be modified to allow all of the turbines to operate up to their full nameplate capability, the incremental annual energy output from repowered wind facilities will increase by 30.0 percent (862 GWh per year)—up from the 24.9 percent (714 GWh per year) assumed in my updated economic analysis. As explained in the rebuttal testimony of Mr. Hemstreet, this scenario would require replacing turbine pad-mount transformers, upgrading some segments of collector systems, and retrofitting or replacing certain generator step-up transformers for an incremental combined cost of $36 million.

Q. Please summarize the results of this sensitivity.

A. Table 9 summarizes the results of the sensitivity that assumes use of [redacted] turbines with modified LGIAs. To assess the potential impact of deploying this equipment, the PVRR(d) was calculated through 2036 based on the SO model and PaR, and these results are presented alongside the comparable benchmark study which assumed use of [redacted] turbines. The sensitivity reflects medium natural gas and medium CO_2 price-policy assumptions and shows that the benefits of deploying the [redacted] turbines with modified LGIAs range between $37 million to $48 million before accounting for the sizable increase to incremental energy output from the repowered wind projects beyond 2036.

Table 9. LGIA-Modified Equipment Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($186)	($138)	($48)
PaR Stochastic Mean	($153)	($115)	($37)
PaR Risk Adjusted	($160)	($121)	($39)

GENERAL MODELING ASSUMPTIONS

Q. Mr. Hayet claims that the Company's economic analysis assumes that each of the nine price-policy scenarios studied (*e.g.*, high gas/high CO_2, medium gas/medium CO_2, low gas/low CO_2) are all equally likely to occur. (Hayet Direct, lines 165-72.) Is this a correct understanding of the Company's analysis?

A. No. Mr. Hayet's claim implies that, without an explicit weighting for each price-policy scenario, each scenario is equally likely to occur. While application of a weighting factor to each price-policy scenario could as a matter of convenience be used to produce a single, probability-weighted PVRR(d) outcome, it is problematic because there is no way to develop empirically derived probability assumptions. Rather, assigning probability assumptions would be a highly subjective exercise largely informed by individual opinion.

The price-policy scenario assuming medium natural-gas prices and medium CO_2 prices represents the central forecast, around which the impact of lower or higher price assumptions can be evaluated. The PVRR(d) net benefit of wind repowering in the updated economic analysis derived from the central price-policy scenario is $471 million when calculated off of the forecasted change in annual revenue requirement through 2050. This outcome indicates that when central price-policy assumptions are used, there is a reasonably sized cushion in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices and CO_2 prices end up lower than what is assumed in this scenario. The other price-policy scenarios are useful in quantifying how sensitive the PVRR(d) results are to these key assumptions and provide a foundation for judging risk. In the updated economic analysis, customer benefits from the wind repowering project increase relative to the results from my original analysis and remain substantial in low natural-gas price and low CO_2 price scenarios, and there is significant upside to the projected customer benefits if these price assumptions are higher than in the central price-policy scenario.

Q. Mr. Peaco alleges that because there is no current price on carbon emissions, the scenarios with zero carbon price may be the most likely outcome. (Peaco Direct, lines 600-606.) Do you agree?

A. No. It is simply not reasonable to conclude that today's policy environment is the best indicator of the policy environment we can expect over the next three decades. It is even more unreasonable to dismiss the results of scenarios developed to quantify the economic impact of potential environmental policy outcomes that could impute a financial cost on CO_2 emissions at some point over the next three decades. While it is *possible* that no such policy will materialize, as contemplated in certain price-policy scenarios, it does not mean that given the current policy environment, it is the *most likely* scenario.

Q. Mr. Peaco also points out that relatively small changes in assumptions, for example, a one-percent reduction in generation, can have a significant impact on customer benefits. (Peaco Direct, lines 830-831.) How do you respond?

A. Mr. Peaco calculates the potential impact on the PVRR(d) value of federal PTC benefits assuming a one-percent reduction in generation from the repowered wind facilities. PacifiCorp's wind generation forecast for the repowered wind facilities is derived by applying the incremental increase in energy output calculated from actual operating data to the actual historical wind generation from each wind facility since it was originally placed in service. Because this forecast is tied to actual generation and actual turbine output data resulting from the actual experienced wind conditions at the existing wind facilities, I have a high degree of confidence in the generation forecasts used in the economic analysis.

Mr. Peaco does not testify that PacifiCorp's wind generation forecasts are invalid. He simply asserts that there is potential risk to the overall economics of the wind generation output were reduced by one percent. This one-sided risk assessment fails to quantify the potential upside benefits if wind generation exceeds the assumed forecast used in the economic analysis by one percent. Using Mr. Peaco's calculations, the PVRR(d) benefits calculated from the change in system costs through 2050 assuming medium natural-gas price and medium CO_2 price-policy assumptions would be reduced from $471 million to $462 million if wind generation data were one percent lower than assumed and be increased from $471 million to $480 million if wind generation data were one percent higher than assumed.

Q. Mr. Hayet claims that the repowering project will provide little additional value if the Company also acquires the new wind facilities and constructs the new transmission facilities that are also contemplated in the 2017 IRP. (Hayet Direct, lines 532 - 535.) Is this a fair criticism?

A. No. Mr. Hayet misinterprets the sensitivity analysis summarized in my direct testimony that reports the PVRR(d) benefits of wind repowering if implemented along with PacifiCorp's proposed new wind resources and new transmission line. This sensitivity showed that when both projects are implemented together, the PVRR(d) benefits of all projects (wind repowering, new wind, and new transmission) are between $219 million and $230 million higher when calculated from system costs through 2036, than the benefits of wind repowering as a stand-alone project.

I present the same sensitivity study in the economic analysis of the new wind and transmission projects in Docket No. 17-035-40; however, the economic impact of all projects (wind repowering, new wind, and new transmission) is compared to the PVRR(d) results of the new wind and transmission investments as a stand-alone project. This sensitivity shows a modest reduction in the PVRR(d) benefits of all of the projects relative to the new wind and transmission investments as a stand-alone project when calculated from PaR results through 2036. Results from the SO model based on projections through 2036 show increased benefits from when all projects are added to the system. Most importantly, the results do not capture *any* of the incremental benefits from wind repowering beyond 2036, and therefore do not include any of the incremental benefits associated with the significant increase in the expected annual energy output from the repowered wind facilities beyond the period in which the existing wind facilities would have otherwise reached the end of their lives.

CONCLUSION

Q. Please summarize the conclusions of your rebuttal testimony.

A. The updated economic analysis summarized in my rebuttal testimony supports repowering just over 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The updated economic analysis shows significant net customer benefits in all of the scenarios analyzed. The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power costs, and deliver substantial federal PTC benefits that will be passed on to customers. The proposed wind repowering project is in the public interest.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-1R)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Rebuttal Testimony of Rick T. Link

Wind-Facility Data

October 2017

[redacted]

Existing Wind Prior to Repowering

	Capacity (MW)	LGIA Limited Capacity (MW)	Energy (MWh)	Capacity Factor	Repower Capital Investment ($m)	Date PTC Ends	End-of-Life Date	Repower Date
Glenrock 1	99.0	99.0	303,723	35.0%	n/a	12/30/2018	12/31/2038	n/a
Glenrock 3	39.0	39.0	113,438	33.2%	n/a	1/16/2019	12/31/2038	n/a
Seven Mile Hill 1	99.0	99.0	339,195	39.1%	n/a	12/30/2018	12/31/2038	n/a
Seven Mile Hill 2	19.5	19.5	71,224	41.7%	n/a	12/30/2018	12/31/2038	n/a
High Plains	99.0	99.0	306,145	35.3%	n/a	9/12/2019	12/31/2038	n/a
McFadden Ridge	28.5	28.5	93,101	37.3%	n/a	9/28/2019	12/31/2038	n/a
Dunlap Ranch	111.0	111.0	389,045	40.0%	n/a	9/30/2020	10/1/2040	n/a
Rolling Hills	99.0	99.0	271,635	31.3%	n/a	1/16/2019	12/31/2038	n/a
Leaning Juniper	100.5	100.5	233,592	26.5%	n/a	9/13/2016	9/14/2036	n/a
Marengo 1	140.4	140.4	360,279	29.3%	n/a	8/2/2017	8/1/2037	n/a
Marengo 2	70.2	70.2	166,742	27.1%	n/a	6/25/2018	6/1/2038	n/a
Goodnoe Hills	94.0	94.0	220,898	26.8%	n/a	5/31/2018	12/31/2038	n/a
Total	999.1	999.1	2,869,016	32.8%				

Repowered Wind

	Capacity (MW)	LGIA Limited Capacity (MW)	LGIA Limited Energy (MWh)	LGIA Limited Capacity Factor	Repower Capital Investment ($m)	Date PTC Ends	End-of-Life Date	Repower Date
Glenrock 1	107.8	99.0	367,560	42.4%	[redacted]	9/30/2029	10/1/2049	10/1/2019
Glenrock 3	42.2	39.0	134,332	39.3%		9/30/2029	10/1/2049	10/1/2019
Seven Mile Hill 1	108.6	99.0	413,496	47.7%		6/30/2029	7/1/2049	7/1/2019
Seven Mile Hill 2	21.4	19.5	86,826	50.8%		6/30/2029	7/1/2049	7/1/2019
High Plains	108.6	99.0	375,709	43.3%		10/31/2029	11/1/2049	11/1/2019
McFadden Ridge	31.3	28.5	114,486	45.9%		10/31/2029	11/1/2049	11/1/2019
Dunlap Ranch	121.7	111.0	473,533	48.7%		11/30/2030	12/1/2050	12/1/2020
Rolling Hills	106.8	99.0	316,417	36.5%		9/30/2029	10/1/2049	10/1/2019
Leaning Juniper	120.6	100.5	303,761	34.5%		9/30/2029	10/1/2049	10/1/2019
Marengo 1	156.0	140.4	484,612	39.4%		10/31/2029	11/1/2049	11/1/2019
Marengo 2	78.0	70.2	228,704	37.2%		10/31/2029	11/1/2049	11/1/2019
Goodnoe Hills	103.4	94.0	283,696	34.5%		9/30/2029	10/1/2049	10/1/2019
Total	1,106.2	999.1	3,583,132	37.0%	$1,083			

[redacted]

Run-Rate Capital

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
All Repowered Projects	($9.8)	($14.7)	($19.6)	($20.5)	($19.8)	($18.0)	($17.9)	($15.2)	($13.2)	($11.4)	($9.6)	($9.9)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	($8.7)	($4.4)	($2.3)	($1.8)	($1.8)	($1.8)	($1.9)	($1.0)	$1.0	$9.2	$16.5	$17.0

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$18.6	$19.0	$19.4	$19.9	$20.3	$20.8	$21.3	$21.8	$12.5	$1.4

Run-Rate Operations and Maintenance Expense

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
All Repowered Projects	$0.0	$0.0	$3.9	$12.1	$12.8	$9.6	$9.5	$9.3	$9.2	$9.1	$8.9	$8.8

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	$5.9	$2.2	$1.1	$1.1	$1.2	$1.2	$1.2	$2.0	$5.5	$13.7	$28.1	$29.5

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$32.3	$33.0	$33.8	$34.6	$35.4	$36.2	$37.0	$37.9	$29.9	$2.6

Rocky Mountain Power
Exhibit RMP___(RTL-2R)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Rick T. Link

SO Model Annual Results

October 2017

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($184)	$1	$3	$1	($13)	($16)	($16)	($17)	($17)	($19)	($19)	($20)	($21)	($23)	($28)	($29)	($29)	($27)	($27)	($53)	($63)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($12)	$0	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($4)	($5)	($5)
Change in System Fixed Cost	$19	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$4	$4	$4	($8)	$5	$4	$19	$33
Net (Benefit)/Cost	($110)	$6	$7	$7	($7)	($10)	($11)	($11)	($12)	($13)	($14)	($15)	($16)	($14)	($19)	($20)	($32)	($18)	($19)	($32)	($27)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($162)	$1	$2	$1	($14)	($17)	($17)	($19)	($19)	($21)	($21)	($22)	($25)	($25)	($28)	($29)	($26)	($29)	($29)	($3)	$4
Change in Emissions	($5)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($3)	($1)	($2)	$1	$1
Change in DSM	$24	$0	$1	$1	$1	$1	$1	$3	$3	$3	$3	$3	$3	$3	$4	$5	$5	$5	$5	$3	$2
Change in System Fixed Cost	($48)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($5)	($6)	($36)	($50)	($62)
Net (Benefit)/Cost	($125)	$6	$7	$7	($8)	($10)	($10)	($10)	($10)	($13)	($13)	($14)	($16)	($17)	($18)	($19)	($22)	($24)	($54)	($42)	($46)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($155)	$1	$3	$1	($14)	($16)	($16)	($17)	($18)	($19)	($19)	($19)	($21)	($21)	($22)	($24)	($24)	($18)	($18)	($28)	($27)
Change in Emissions	($32)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($2)	($5)	($7)	($9)	($9)	($10)	($11)	($3)	($3)	($12)	($13)
Change in DSM	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	($11)	$0	$0	($0)	($0)	$0	$0	$0	$0	($0)	$0	$0	($0)	($0)	($2)	$0	$0	($15)	($16)	($0)	($0)
Net (Benefit)/Cost	($133)	$6	$7	$7	($8)	($10)	($10)	($11)	($11)	($14)	($15)	($18)	($22)	($24)	($26)	($27)	($28)	($29)	($31)	($32)	($33)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($192)	$1	$3	$1	($13)	($16)	($17)	($18)	($20)	($23)	($23)	($24)	($26)	($26)	($29)	($30)	($31)	($35)	($31)	($36)	($38)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	$2	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Change in System Fixed Cost	($14)	$0	$0	($0)	($0)	$0	$0	($0)	$0	($0)	$0	($0)	($0)	($5)	($5)	($5)	($5)	($2)	($7)	($7)	($7)
Net (Benefit)/Cost	($137)	$6	$7	$7	($8)	($11)	($12)	($12)	($14)	($16)	($16)	($17)	($19)	($24)	($26)	($27)	($28)	($28)	($29)	($34)	($36)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($195)	$1	$3	$1	($13)	($16)	($17)	($18)	($20)	($23)	($23)	($24)	($25)	($29)	($32)	($33)	($34)	($26)	($36)	($38)	($39)
Change in Emissions	($6)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($2)	($1)	($2)	($1)	($1)	($1)	($0)	($0)	($1)	($1)	($1)
Change in DSM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in System Fixed Cost	($3)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	$0	$0	$0	($10)	$0	$0	$0
Net (Benefit)/Cost	($138)	$6	$7	$7	($8)	($11)	($12)	($12)	($14)	($18)	($18)	($19)	($21)	($23)	($25)	($27)	($28)	($29)	($29)	($31)	($32)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($186)	$1	$3	$1	($13)	($16)	($17)	($18)	($20)	($24)	($23)	($23)	($28)	($22)	($28)	($29)	($28)	($32)	($33)	($34)	($34)
Change in Emissions	($33)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($6)	($5)	($6)	($8)	($9)	($11)	($8)	($9)	($11)	($13)
Change in DSM	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in System Fixed Cost	($3)	$0	$0	($0)	($0)	$0	$0	$0	$0	($0)	$0	$0	($0)	($7)	$0	$0	$0	$0	$0	$0	$0
Net (Benefit)/Cost	($157)	$6	$7	$7	($8)	($11)	($11)	($12)	($14)	($19)	($20)	($22)	($26)	($28)	($30)	($31)	($32)	($33)	($35)	($37)	($39)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($237)	$2	$4	$1	($19)	($24)	($25)	($23)	($26)	($27)	($27)	($28)	($31)	($33)	($36)	($38)	($39)	($34)	($39)	($42)	($45)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($26)	$0	$0	($0)	($0)	$0	$0	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($3)	($3)	($3)	($8)	($6)	($9)	($5)
Net (Benefit)/Cost	($196)	$6	$8	$7	($13)	($18)	($19)	($21)	($23)	($24)	($24)	($25)	($28)	($30)	($32)	($33)	($34)	($35)	($37)	($44)	($42)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($224)	$2	$4	$1	($19)	($25)	($26)	($27)	($30)	($31)	($31)	($32)	($35)	($38)	($41)	$18	($26)	($33)	($33)	($30)	($45)
Change in Emissions	($4)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	$1	($1)	($1)	($1)	($2)	($1)
Change in DSM	($2)	$0	$0	$0	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in System Fixed Cost	($41)	$0	$0	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	($64)	($16)	($12)	($18)	($18)	($8)
Net (Benefit)/Cost	($204)	$6	$8	$7	($13)	($18)	($19)	($20)	($22)	($24)	($24)	($26)	($29)	($31)	($34)	($38)	($36)	($38)	($45)	($42)	($47)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($247)	$2	$4	$1	($19)	($24)	($24)	($25)	($28)	($29)	($30)	($30)	($26)	($33)	($40)	($33)	($35)	($37)	($45)	($51)	($54)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($3)	($5)	($4)	($3)	($3)	($5)	($6)	($4)	($5)
Change in DSM	($6)	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	($11)	$0	$0	($0)	($0)	$0	$0	($0)	$0	$0	($0)	$0	($9)	($2)	$1	($7)	($7)	($5)	$0	$0	$0
Net (Benefit)/Cost	($214)	$6	$8	$7	($13)	($18)	($19)	($20)	($23)	($25)	($26)	($28)	($31)	($34)	($37)	($37)	($38)	($40)	($44)	($47)	($51)

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($164)	$1	$2	$1	($11)	($13)	($14)	($15)	($15)	($16)	($16)	($16)	($20)	($22)	($25)	($26)	($27)	($24)	($24)	($49)	($57)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($2)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)
Change in DSM	($13)	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($3)	($4)	($6)	($6)
Change in Deficiency	$3	($0)	$0	($0)	$0	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($1)	($1)	$1	$6	($2)	$1	$6
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$19	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$4	$4	$4	($8)	$5	$4	$19	$33
Net (Benefit)/Cost	($90)	$5	$7	$6	($6)	($8)	($9)	($9)	($10)	($10)	($11)	($12)	($16)	($14)	($18)	($19)	($29)	($10)	($19)	($27)	($17)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($141)	$1	$2	$0	($12)	($13)	($14)	($15)	($16)	($17)	($17)	($18)	($23)	($24)	($26)	($28)	($26)	($25)	($25)	($1)	$5
Change in Emissions	($7)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	$1	$2
Change in VOM	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($0)	$0
Change in DSM	$27	$0	$1	$1	$1	$1	$1	$3	$3	$3	$3	$3	$3	$3	$5	$5	$5	$5	$5	$3	$2
Change in Deficiency	($4)	($0)	($0)	$0	$0	$0	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($1)	($0)	($2)	($8)	$3	($1)	($3)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($48)	$0	$0	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($5)	($6)	($36)	($50)	($62)
Net (Benefit)/Cost	($108)	$5	$7	$7	($6)	($6)	($7)	($7)	($7)	($9)	($9)	($10)	($15)	($16)	($18)	($18)	($24)	($29)	($49)	($41)	($48)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($138)	$1	$2	$1	($12)	($13)	($13)	($14)	($14)	($15)	($16)	($18)	($22)	($22)	($21)	($22)	($23)	($15)	($16)	($27)	($26)
Change in Emissions	($25)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($5)	($6)	($8)	($6)	($8)	($7)	($2)	($3)	($9)	($7)
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)
Change in Deficiency	($3)	($0)	($0)	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	$0	$0	($3)	($4)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($11)	$0	$0	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($2)	$0	$0	($15)	($16)	($0)	($0)
Net (Benefit)/Cost	($114)	$5	$7	$6	($6)	($7)	($7)	($8)	($8)	($11)	($13)	($16)	($23)	($25)	($22)	($24)	($24)	($26)	($27)	($32)	($31)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($165)	$1	$2	$1	($11)	($13)	($13)	($14)	($16)	($18)	($18)	($19)	($25)	($25)	($26)	($28)	($28)	($32)	($28)	($32)	($35)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)
Change in DSM	$3	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Change in Deficiency	($4)	($0)	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0	($0)	($0)	($0)	($1)	($2)	($1)	($5)	($1)	($2)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($14)	$0	$0	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	($0)	($5)	($5)	($5)	($5)	($2)	($7)	($7)	($7)
Net (Benefit)/Cost	($116)	$5	$6	$6	($6)	($7)	($8)	($9)	($10)	($11)	($11)	($12)	($19)	($22)	($24)	($26)	($27)	($28)	($31)	($31)	($35)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($167)	$1	$2	$1	($11)	($13)	($13)	($14)	($16)	($18)	($18)	($18)	($25)	($27)	($29)	($31)	($32)	($25)	($30)	($31)	($32)
Change in Emissions	($7)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in Deficiency	($3)	($0)	($0)	$0	$0	($0)	($0)	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($1)	($2)	($2)	($1)	($3)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($3)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	$0	$0	$0	($10)	$0	$0	$0
Net (Benefit)/Cost	($115)	$5	$7	$6	($6)	($7)	($8)	($9)	($10)	($13)	($13)	($14)	($21)	($22)	($24)	($26)	($27)	($30)	($27)	($26)	($29)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($159)	$1	$2	$1	($11)	($13)	($13)	($14)	($16)	($18)	($18)	($19)	($25)	($21)	($25)	($26)	($27)	($28)	($29)	($31)	($32)
Change in Emissions	($30)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($5)	($6)	($6)	($6)	($7)	($8)	($8)	($10)	($9)	($9)
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in Deficiency	($3)	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($2)	($3)	($1)	($3)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($3)	$0	$0	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	($7)	$0	$0	$0	$0	$0	$0	$0
Net (Benefit)/Cost	($131)	$5	$7	$6	($6)	($7)	($8)	($8)	($10)	($14)	($15)	($18)	($25)	($28)	($25)	($27)	($28)	($31)	($34)	($33)	($36)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($189)	$1	$3	$1	($15)	($17)	($19)	($18)	($19)	($20)	($20)	($21)	($28)	($31)	($29)	($31)	($33)	($27)	($31)	($33)	($35)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in Deficiency	($3)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	($0)	($0)	($2)	($2)	($1)	($2)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($26)	$0	$0	($0)	($0)	$0	$0	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($3)	($3)	($3)	($8)	($6)	($9)	($5)
Net (Benefit)/Cost	($152)	$6	$7	$6	($10)	($12)	($13)	($15)	($17)	($17)	($17)	($18)	($26)	($28)	($25)	($27)	($29)	($30)	($32)	($36)	($34)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$67	$4	$4	$6	$6	$6	$6	$6	$6	$6	$6	$7	$7	$7	$7	$7	$7	$7	$8	$8	$8
Change in NPC	($182)	$1	$3	$1	($15)	($18)	($20)	($21)	($22)	($23)	($24)	($24)	($32)	($35)	($33)	$14	($24)	($27)	($28)	($27)	($37)
Change in Emissions	($4)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	$2	($1)	($1)	($1)	($1)	($1)
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)
Change in DSM	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in Deficiency	($3)	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$0	($0)	($0)	($0)	($2)	($3)	($2)	($4)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($41)	$0	$0	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	($64)	($16)	($12)	($18)	($18)	($8)
Net (Benefit)/Cost	($167)	$6	$7	$7	($10)	($11)	($12)	($14)	($15)	($17)	($17)	($18)	($26)	($28)	($26)	($41)	($35)	($36)	($43)	($41)	($43)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036

Rocky Mountain Power
Exhibit RMP___(RTL-3R)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results

October 2017

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($526)	$1	$2	$1	($11)	($13)	($14)	($15)	($15)	($16)	($16)	($16)	($20)	($22)	($25)	($26)	($27)	($24)	($24)	($49)	($57)	($58)	($81)	($148)	($154)	($172)	($176)	($180)	($184)	($188)	($192)	($196)	($183)	($124)	($20)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($46)	($0)	$0	($0)	$0	($0)	($0)	($0)	($1)	($1)	($2)	($2)	($2)	($3)	($3)	($4)	($2)	$2	($7)	($5)	($1)	($6)	($8)	($14)	($15)	($16)	($17)	($17)	($17)	($18)	($18)	($19)	($17)	($12)	($2)
System Fixed Costs	$96	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$4	$4	$4	($8)	$5	$4	$19	$33	$12	$17	$31	$33	$36	$37	$38	$39	$40	$41	$42	$39	$26	$4
Net System Impacts	($476)	$1	$2	$1	($11)	($14)	($14)	($15)	($16)	($16)	($18)	($18)	($22)	($21)	($25)	($26)	($36)	($17)	($26)	($35)	($25)	($52)	($72)	($131)	($136)	($152)	($155)	($159)	($162)	($166)	($169)	($173)	($162)	($109)	($17)
2050 Net (Benefit)/Cost	($360)	$1	$2	($3)	($8)	($31)	($45)	($61)	($70)	($81)	($92)	($96)	($110)	($77)	$20	$38	$22	$36	$30	$9	$13	$1	$10	($17)	($19)	($28)	($31)	($33)	($35)	($36)	($38)	($34)	($17)	($24)	($13)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($397)	$1	$2	$0	($12)	($13)	($14)	($15)	($16)	($17)	($17)	($18)	($23)	($24)	($26)	($28)	($26)	($25)	($25)	($1)	$5	($41)	($58)	($105)	($109)	($122)	($125)	($127)	($130)	($133)	($136)	($139)	($130)	($88)	($14)
Emissions	($25)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	$1	$2	($3)	($4)	($7)	($8)	($9)	($9)	($9)	($9)	($10)	($10)	($10)	($9)	($6)	($1)
Other Variable Costs	$54	$0	$1	$1	$1	$1	$1	$3	$3	$3	$3	$3	$3	$3	$4	$5	$3	($3)	$7	$2	($1)	$5	$8	$14	$14	$16	$16	$17	$17	$17	$18	$18	$17	$11	$2
System Fixed Costs	($228)	$0	$0	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($5)	($6)	($36)	($50)	($62)	($29)	($41)	($74)	($77)	($86)	($87)	($89)	($91)	($93)	($96)	($98)	($91)	($62)	($10)
Net System Impacts	($596)	$1	$2	$1	($11)	($12)	($13)	($13)	($13)	($15)	($16)	($17)	($22)	($23)	($25)	($25)	($31)	($36)	($56)	($48)	($56)	($68)	($95)	($172)	($179)	($200)	($205)	($209)	($214)	($219)	($223)	($228)	($213)	($144)	($23)
2050 Net (Benefit)/Cost	($480)	$1	$2	($3)	($8)	($29)	($44)	($58)	($66)	($80)	($90)	($95)	($109)	($80)	$20	$39	$28	$17	$0	($4)	($17)	($15)	($13)	($58)	($62)	($77)	($80)	($84)	($87)	($89)	($92)	($89)	($68)	($59)	($18)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($407)	$1	$2	$1	($12)	($13)	($13)	($14)	($14)	($15)	($16)	($18)	($22)	($22)	($21)	($22)	($23)	($15)	($16)	($27)	($26)	($43)	($61)	($110)	($114)	($128)	($131)	($134)	($137)	($140)	($143)	($146)	($136)	($92)	($15)
Emissions	($103)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($5)	($6)	($8)	($6)	($8)	($7)	($2)	($3)	($9)	($7)	($13)	($18)	($32)	($33)	($37)	($38)	($39)	($40)	($40)	($41)	($42)	($39)	($27)	($4)
Other Variable Costs	($27)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)	($0)	($0)	($4)	($5)	($3)	($5)	($9)	($9)	($10)	($10)	($10)	($11)	($11)	($11)	($11)	($11)	($7)	($1)
System Fixed Costs	($52)	$0	$0	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($2)	$0	$0	($15)	($16)	($0)	($0)	($7)	($9)	($17)	($17)	($19)	($20)	($20)	($21)	($21)	($22)	($22)	($21)	($14)	($2)
Net System Impacts	($588)	$1	$2	$1	($12)	($13)	($13)	($14)	($14)	($17)	($19)	($23)	($29)	($32)	($29)	($31)	($32)	($33)	($35)	($40)	($39)	($66)	($92)	($167)	($174)	($194)	($198)	($203)	($207)	($212)	($217)	($221)	($207)	($140)	($22)
2050 Net (Benefit)/Cost	($473)	$1	$2	($3)	($9)	($29)	($44)	($60)	($68)	($82)	($94)	($101)	($117)	($88)	$15	$33	$27	$20	$22	$4	$0	($13)	($10)	($53)	($57)	($71)	($74)	($77)	($80)	($83)	($85)	($82)	($62)	($55)	($18)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($518)	$1	$2	$1	($11)	($13)	($13)	($14)	($16)	($18)	($18)	($19)	($25)	($25)	($26)	($28)	($28)	($32)	($28)	($32)	($35)	($57)	($79)	($144)	($150)	($168)	($171)	($175)	($179)	($183)	($187)	($191)	($179)	($121)	($19)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($13)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$1	$1	$1	$0	$0	($0)	($1)	($1)	($1)	($4)	($0)	($2)	($2)	($2)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($5)	($4)	($1)
System Fixed Costs	($68)	$0	$0	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	($0)	($5)	($5)	($5)	($5)	($2)	($7)	($7)	($7)	($9)	($12)	($22)	($23)	($25)	($26)	($27)	($27)	($28)	($28)	($29)	($27)	($18)	($3)
Net System Impacts	($599)	$1	$2	$1	($12)	($13)	($14)	($15)	($16)	($18)	($18)	($18)	($25)	($29)	($31)	($33)	($34)	($35)	($39)	($39)	($43)	($67)	($94)	($170)	($177)	($198)	($202)	($207)	($212)	($216)	($221)	($226)	($211)	($142)	($23)
2050 Net (Benefit)/Cost	($483)	$1	$2	($3)	($8)	($30)	($45)	($60)	($70)	($82)	($92)	($96)	($113)	($86)	$14	$31	$25	$18	$18	$5	($5)	($15)	($12)	($56)	($60)	($75)	($78)	($81)	($85)	($87)	($89)	($87)	($66)	($58)	($18)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($526)	$1	$2	$1	($11)	($13)	($13)	($14)	($16)	($18)	($18)	($18)	($25)	($27)	($29)	($31)	($32)	($25)	($30)	($31)	($32)	($58)	($81)	($147)	($153)	($171)	($175)	($179)	($183)	($187)	($191)	($195)	($182)	($123)	($20)
Emissions	($24)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($3)	($4)	($7)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($9)	($6)	($1)
Other Variable Costs	($22)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($0)	($1)	($1)	($2)	($2)	($3)	($1)	($3)	($3)	($4)	($7)	($7)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($8)	($6)	($1)
System Fixed Costs	($15)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	$0	$0	$0	($10)	$0	$0	$0	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($4)	($1)
Net System Impacts	($587)	$1	$2	$1	($11)	($13)	($14)	($15)	($16)	($19)	($20)	($20)	($27)	($29)	($31)	($33)	($35)	($37)	($34)	($34)	($37)	($65)	($91)	($166)	($173)	($193)	($197)	($201)	($206)	($210)	($215)	($220)	($205)	($139)	($22)
2050 Net (Benefit)/Cost	($471)	$1	$2	($3)	($8)	($30)	($45)	($60)	($70)	($84)	($94)	($98)	($115)	($85)	$14	$31	$24	$16	$22	$10	$1	($13)	($9)	($52)	($56)	($69)	($73)	($76)	($79)	($81)	($83)	($81)	($60)	($54)	($17)

Estimated Annual Revenue Requirement Results ($ million)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($491)	$1	$2	$1	($11)	($13)	($13)	($14)	($16)	($18)	($18)	($19)	($25)	($21)	($25)	($26)	($27)	($28)	($29)	($31)	($32)	($54)	($75)	($136)	($141)	($158)	($161)	($165)	($169)	($172)	($176)	($180)	($168)	($113)	($18)
Emissions	($124)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($5)	($6)	($6)	($6)	($7)	($8)	($8)	($10)	($9)	($9)	($15)	($21)	($38)	($40)	($45)	($46)	($47)	($48)	($49)	($50)	($51)	($48)	($32)	($5)
Other Variable Costs	($20)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($2)	($3)	($1)	($3)	($2)	($3)	($6)	($7)	($7)	($7)	($8)	($8)	($8)	($8)	($8)	($8)	($5)	($1)
System Fixed Costs	($14)	$0	$0	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	($7)	$0	$0	$0	$0	$0	$0	$0	($2)	($2)	($4)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($5)	($4)	($1)
Net System Impacts	($649)	$1	$2	$1	($11)	($13)	($14)	($14)	($16)	($20)	($22)	($24)	($32)	($34)	($32)	($34)	($36)	($38)	($42)	($41)	($44)	($73)	($102)	($185)	($192)	($215)	($220)	($225)	($229)	($235)	($240)	($245)	($229)	($155)	($25)
2050 Net (Benefit)/Cost	($534)	$1	$2	($3)	($8)	($30)	($45)	($60)	($70)	($85)	($96)	($102)	($119)	($91)	$13	$30	$23	$15	$15	$4	($5)	($20)	($20)	($71)	($76)	($91)	($95)	($99)	($103)	($105)	($108)	($106)	($84)	($70)	($20)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($571)	$1	$3	$1	($15)	($17)	($19)	($18)	($19)	($20)	($20)	($21)	($28)	($31)	($29)	($31)	($33)	($27)	($31)	($33)	($35)	($62)	($86)	($156)	($163)	($182)	($186)	($190)	($194)	($198)	($203)	($207)	($194)	($131)	($21)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($16)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)	($3)	($1)	($2)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($4)	($1)
System Fixed Costs	($84)	$0	$0	($0)	($0)	$0	$0	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($3)	($3)	($3)	($8)	($6)	($9)	($5)	($10)	($13)	($24)	($25)	($28)	($29)	($29)	($30)	($31)	($31)	($32)	($30)	($20)	($3)
Net System Impacts	($671)	$1	$3	$1	($15)	($18)	($19)	($21)	($23)	($24)	($24)	($24)	($32)	($35)	($32)	($34)	($36)	($37)	($39)	($44)	($42)	($73)	($102)	($185)	($193)	($215)	($220)	($225)	($230)	($235)	($240)	($246)	($229)	($155)	($25)
2050 Net (Benefit)/Cost	($555)	$1	$2	($3)	($12)	($34)	($50)	($67)	($76)	($88)	($98)	($103)	($120)	($92)	$13	$30	$23	$16	$17	$0	($3)	($20)	($20)	($71)	($76)	($92)	($96)	($99)	($103)	($106)	($108)	($107)	($84)	($70)	($20)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($499)	$1	$3	$1	($15)	($18)	($20)	($21)	($22)	($23)	($24)	($24)	($32)	($35)	($33)	$14	($24)	($27)	($28)	($27)	($37)	($51)	($71)	($129)	($135)	($151)	($154)	($157)	($161)	($164)	($168)	($172)	($160)	($108)	($17)
Emissions	($11)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	$2	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($3)	($0)
Other Variable Costs	($27)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($0)	($1)	($1)	($1)	($3)	($4)	($2)	($4)	($3)	($5)	($8)	($9)	($10)	($10)	($10)	($10)	($11)	($11)	($11)	($10)	($7)	($1)
System Fixed Costs	($214)	$0	$0	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	($64)	($16)	($12)	($18)	($18)	($8)	($28)	($39)	($71)	($74)	($83)	($84)	($86)	($88)	($90)	($92)	($94)	($88)	($59)	($9)
Net System Impacts	($751)	$1	$3	$1	($15)	($17)	($18)	($20)	($21)	($23)	($24)	($24)	($32)	($35)	($33)	($49)	($42)	($43)	($51)	($48)	($51)	($84)	($117)	($212)	($221)	($246)	($252)	($257)	($263)	($269)	($275)	($281)	($262)	($177)	($28)
2050 Net (Benefit)/Cost	($635)	$1	$2	($3)	($12)	($34)	($49)	($65)	($75)	($88)	($98)	($103)	($120)	($91)	$11	$16	$17	$10	$6	($4)	($12)	($31)	($35)	($98)	($104)	($123)	($128)	($132)	($136)	($140)	($143)	($142)	($117)	($92)	($24)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$866	($1)	($2)	$20	$111	$114	$103	$94	$87	$81	$77	$73	$70	$66	$63	$62	$57	$51	$54	$42	$35	$46	$66	$81	$83	$86	$86	$86	$86	$88	$90	$96	$102	$51	$1
O&M	$132	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$19	($0)	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($902)	$1	$2	($28)	($120)	($145)	($145)	($150)	($150)	($156)	($161)	($161)	($167)	($130)	($22)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$116	($0)	($0)	($4)	$3	($17)	($31)	($46)	($54)	($65)	($75)	($78)	($87)	($57)	$45	$64	$59	$53	$57	$44	$39	$53	$82	$114	$117	$123	$124	$125	$127	$129	$132	$139	$145	$85	$5
System Impacts																																			
NPC	($561)	$1	$3	$1	($15)	($17)	($18)	($19)	($21)	($22)	($22)	($23)	($23)	($26)	($31)	($26)	($28)	($29)	($34)	($37)	($39)	($60)	($83)	($151)	($158)	($176)	($180)	($184)	($188)	($192)	($196)	($201)	($187)	($127)	($20)
Emissions	($90)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($3)	($5)	($5)	($5)	($5)	($6)	($7)	($7)	($7)	($11)	($15)	($28)	($29)	($32)	($33)	($34)	($34)	($35)	($36)	($37)	($34)	($23)	($4)
Other Variable Costs	($31)	($0)	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($3)	($3)	($1)	($4)	($3)	($5)	($9)	($9)	($10)	($10)	($11)	($11)	($11)	($11)	($12)	($11)	($7)	($1)
System Fixed Costs	($53)	$0	$0	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	($9)	($2)	$1	($7)	($7)	($5)	$0	$0	$0	($7)	($9)	($17)	($18)	($20)	($20)	($21)	($21)	($22)	($22)	($23)	($21)	($14)	($2)
Net System Impacts	($735)	$1	$3	$1	($15)	($18)	($19)	($20)	($22)	($24)	($26)	($28)	($37)	($34)	($37)	($39)	($41)	($43)	($44)	($45)	($50)	($81)	($113)	($205)	($213)	($238)	($244)	($249)	($254)	($260)	($266)	($272)	($254)	($171)	($27)
2050 Net (Benefit)/Cost	($619)	$1	$2	($3)	($12)	($34)	($50)	($66)	($75)	($89)	($100)	($106)	($124)	($90)	$8	$25	$18	$10	$12	($0)	($11)	($28)	($31)	($91)	($96)	($115)	($119)	($123)	($128)	($131)	($134)	($133)	($109)	($87)	($23)

Rocky Mountain Power
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Jeffrey K. Larsen

October 2017

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

A. Yes.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. In support of the Company's request that the Public Service Commission of Utah ("Commission") approve its energy resource decision for wind repowering, I respond to regulatory policy issues raised in the direct testimonies of Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Charles Peterson and David Thomson, Office of Consumer Services witness Donna Ramas, and the Utah Association of Energy Users witness Kevin C. Higgins. I also provide an update to several of my original direct testimony exhibits as a result of the updated economic analysis prepared by Company witness Mr. Rick T. Link.

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

A. I address the following key issues:

- The appropriateness of the Commission's review of the wind repowering resource decision under Utah Code Ann. § 54-17-402;
- Why the full recovery of the Company's costs of repowering, including undepreciated investment in replaced equipment and a return on investment, is reasonable given the benefits of the repowering project;
- The advantages of the Company's proposed Resource Tracking Mechanism ("RTM") for customers, and the reasonableness of its design; and

- The consistency of the Company's treatment of the costs and benefits of wind repowering with principles of intergenerational equity.

Q. Please summarize your testimony.

A. The Company's request for approval of its resource decision to repower its wind facilities is timely and proper. The Company has carefully developed and refined the wind repowering project. The Company has forecasted the costs and benefits of the project, and addressed the manner in which project risks have been eliminated or mitigated. At the same time, the Company's investment and commitment to the wind repowering project remains limited. This is the right window for meaningful review of the repowering project under Utah Code Ann. § 54-17-402.

The Company proposes to provide all benefits of the wind repowering project to customers. The only "benefit" to the Company is the opportunity to recover its reasonable and prudent costs, like any other resource investment. Unlike most resource investments, however, repowering will result in rate reductions to customers net of the Company's costs, which include undepreciated investment in replaced equipment and a return on the investment. The Company's updated economic analysis for years 2019 through 2022 estimates a Utah customer net benefit in each year, with net benefits of up to $12.4 million by 2022.[1]

The RTM is carefully designed to deliver repowering benefits to customers in a prompt and straightforward manner. The individual components of the RTM are reasonable, and it is a better tool for tracking the costs and benefits of repowering than traditional ratemaking or an accounting order. The Company's overall approach to

[1] See Exhibit RMP__(JKL-2R), line 25 for Utah's allocated share of 2022 Net Customer Benefits of $12.4 million.

tracking the costs and benefits of repowering does not violate the principles of intergenerational equity.

THE COMPANY'S REQUEST IS TIMELY AND PROPER

Q. DPU witness Dr. Zenger questions the appropriateness of the Company's request for preapproval under Utah Code Ann. § 54-17-402 given that, in her estimation, the resource decision has "already been committed to." (Zenger Direct, lines 101 - 105.) Does the Company's request comply with the requirements for preapproval, even considering the repowering project expenditures that occurred in December 2016?

A. Yes. As described in more detail in Mr. Timothy J. Hemstreet's rebuttal testimony, the Company has not unequivocally committed to the wind repowering project. Instead, the Company has prudently negotiated the ability to either not execute contracts or to terminate its future obligations with suppliers and contractors if the resource decision is not approved or economic conditions change such that the project, or a portion of the project, is no longer beneficial to customers.

Q. Dr. Zenger also claims that the Company appears to have made the decision to repower its wind facilities without sufficient public and stakeholder input. (Zenger Direct, 101-125) How do you respond?

A. Contrary to Dr. Zenger's claims, PacifiCorp has not made its decision to repower its wind facilities without sufficient public and stakeholder input. This very proceeding provides a venue for the public and stakeholders to review and provide input on the proposed repowering project. PacifiCorp purchased safe-harbor equipment in December 2016 to secure the *option* to repower its fleet of owned resources and deliver substantial benefits for retail customers. PacifiCorp's request is seeking approval of the proposed wind repowering project, which will require additional incremental investments beyond the safe-harbor equipment purchases made at the end of last year. PacifiCorp's request is not seeking approval of these safe-harbor equipment purchases as standalone investments. Therefore, and contrary to Dr. Zenger's claims, PacifiCorp is not seeking absolution for risk it has already incurred.

Q. Has the Company made similar filings in the past for resource decisions the Company had made, subject to regulatory approval?

A. Yes. The Company has made several resource approval filings under the Energy Resource Procurement Act in Title 54, Chapter 17, including the Deer Creek mine closure, acquisition of Lake Side 2 and Chehalis plants, and approval to install selective catalytic reduction systems at Jim Bridger Units 3 and 4. Each was reviewed and approved by management prior to filing but subject to the regulatory approval process. The suggestion that the Company's contingent review and approval of the repowering project, including purchasing turbines to preserve the opportunity and the benefits of the project, disqualifies the Company from filing for resource approval is contrary to normal business practices and previous resource approval filings.

Q. Dr. Zenger suggests that the repowering project is not a candidate for preapproval because, in essence, it is "fully baked," and parties do not have any real opportunity to collaboratively plan the project. (Zenger Direct, lines 116 - 125.) Does this assertion comport with your understanding of the project's status?

A. No. First, I disagree with Dr. Zenger's contention that parties should be involved in the planning of the project. Parties, and the public generally, are involved in the development of the Company's integrated resource plan, but that is very different from planning the implementation of a project like repowering.

Second, the Company has not unequivocally committed to the repowering project, and will continue to monitor the economics of the project, as reflected in the updated analysis provided by Mr. Link.

Third, the fact the Company is bringing forward a well-developed project should not be viewed as a flaw. As described by Mr. Hemstreet, many of the risks identified by the parties have been mitigated, to a large extent, by the process of negotiating contracts to implement repowering and completing most siting and permitting reviews. If the Company had brought this project to the Commission for preapproval before performing its due diligence and risk mitigation, it would have been more difficult to clearly demonstrate the benefits of the project.

THE CUSTOMER BENEFITS OF REPOWERING JUSTIFY FULL COST RECOVERY

Q. Mr. Peterson recommends that the Company recover the costs of equipment that is replaced as part of the repowering project. But Mr. Peterson also suggests that the Commission "may wish to condition all or part of the recovery for the legacy plant on ratepayer benefits." (Peterson Direct, lines 158 - 165) Is this a reasonable recommendation?

A. No. Mr. Peterson suggests that the Commission limit a portion of the recovery on the legacy plant as a hedge against customer risk. If the Commission determines that the wind repowering project provides customer benefits, there is no basis to limit recovery of costs associated with the project.

The Company included cost recovery of the legacy plant in its economic analysis that demonstrated repowering is lower cost than other alternatives. To reduce the return on the legacy assets would penalize the Company for making the prudent resource selection. It would be analogous to arbitrarily taking a portion of rate base and applying a different rate of return if another resource were selected.

In any forecast of the future, it is unlikely that all assumptions will be completely accurate, especially when looking 30 years into the future. Some assumptions will be low and some will be high. Because of these variances, the Company's modeling includes a range of assumptions that can be used to assess the impact if a particular variable differs from the baseline. This preapproval process is intended to verify the reasonableness of the Company's assumptions and determine that customers will benefit as a result of repowering. If approved, the Company should recover its full cost of service related to the project because it delivers substantial benefits to customers.

Q. Has the Commission previously addressed the replacement of assets with lower cost alternatives?

A. Yes. The Commission has allowed cost recovery of replaced or upgraded assets related to the Powerdale facility, the Deer Creek Mine, and the Carbon coal-fired power plant. In all three cases, the Commission determined that early retirement of these facilities was in the best interest of customers, *i.e.*, retirement provided net savings to customers as compared to continued operation.

Q. Did the Commission penalize the Company in any of these transactions by allowing a lower rate of return on the retired assets?

A. No. In each case, the Commission decided the transaction was a net benefit to customers and allowed the Company its full return on the retired plant. Although there were customer risks associated with the resource decision made in each case, the Commission allowed full recovery.

Q. What do you conclude from these cases?

A. Consistent with this precedent, if the Commission determines that repowering provides customer benefits, based on what is known today, then it should allow full recovery of the costs associated with the upgraded equipment.

Q. Messrs. Peaco and Higgins argue that the repowering project is inequitable because the Company's shareholders will receive substantially more benefits than customers. (Peaco Direct, lines 202 - 215; Higgins Direct, lines 293 - 308.) Do you agree with this characterization?

A. No. The purported shareholder benefit they claim is the capital cost incurred to fund the repowering project. A basic premise of ratemaking, however, is that "a capital-attracting rate of profit is here considered a part of the necessary cost of service."[2] The cost of capital is no different than any other prudent cost recoverable in rates if incurred to provide utility service. It is inaccurate to say that shareholders are receiving a greater benefit than customers based on the fact that shareholders recover the costs incurred to provide utility service.

The Company has demonstrated it can deliver additional generation to customers at a lower cost than the alternatives, resulting in a net benefit to customers. The customer benefits assume that shareholders recover the full cost of the repowering investment, including capital costs.

[2] James C. Bonbright, Albert L. Danielsen, & David R. Kamerschen, *Principles of Public Utility Rates*, 112 (2d ed. Public Utilities Reports 1988).

Moreover, in the near term, the Company's proposed RTM only recovers total project costs to the extent that there are net benefits. After the next rate case, the costs and benefits of repowering will be included in the Company's full revenue requirement. However, there is no guarantee that the Company will recover its full cost of service related to the repowering investment. The Company must prudently manage its costs to achieve the full return allowed by the Commission.

Q. Mr. Higgins recommends that the return on the upgraded equipment should be reduced by 200 basis point to increase customer benefits and decrease Company "benefits." (Higgins Direct, lines 386 – 389.) Is this a reasonable recommendation?

A. No. As discussed above, this proposal incorrectly assumes that cost recovery is a "benefit" to the Company that should be compared to the benefits received by customers. As discussed above, there is no precedent for limiting the Company's recovery of costs when equipment is upgraded or replaced if the upgrade is in customers' interests.

Q. Would the Company "benefit" be any different if another generation resource were selected?

A. Conceptually, no. If the Company invested in any other resource, it would also recover its capital costs, which would be calculated the same way.

RESOURCE TRACKING MECHANISM

Q. Ms. Ramas asserts that the proposed RTM is unnecessary because the Company added rate base in 2015 and 2016 and still earned at or above its authorized rate of return. (Ramas Direct, lines 86 - 108.) Do you agree?

A. No. The RTM is designed to more appropriately match costs and benefits of the wind repowering project than under traditional ratemaking, while ensuring that the project does not impose any additional costs on customers in the near term.

Q. Please explain the impact that the RTM has on earnings.

A. The RTM is a tool to capture the costs and benefits of the wind repowering project and fairly treat shareholders and customers, with the protection of a proposed cap. To the extent costs exceed benefits in any given year until the project is fully reflected in rates, the Company bears the risk. In other words, the RTM is asymmetrical in customers' favor and would credit customers with the net benefits of the project annually until the next general rate case. This would have downward pressure on the Company's earnings, to the extent costs exceed the benefits in any given year.

Q. If the RTM is the point of contention in the proceeding, would the Company be willing to move forward with the wind repowering project without an RTM?

A. Yes, if there is a proper matching of the costs of the project with the benefits so that shareholders are not penalized for making a prudent decision that delivers customer benefits over the long term. If there is no RTM (and therefore no accounting for the incremental costs and production tax credits ("PTCs")), an additional adjustment would be required to remove the zero-cost energy from the Energy Balancing Account ("EBA") and replace the energy at market cost. Under this scenario, the result of repowering would be captured in semi-annual results of operation reports provided to the Commission, and the impact to earnings would be a matter of routine review by the regulatory agencies for reasonableness.

<u>Deferral vs. Accounting Order</u>

Q. What is your position on Mr. Thomson's proposal that the Commission issue an accounting order to defer the costs and benefits of repowering until the next rate case, rather than approve the RTM? (Thomson Direct, lines 169 - 173.)

A. The Company opposes this proposal because it would unreasonably delay recovery of the repowering costs. Under Mr. Thomson's proposal, the Commission would calculate the deferral in the same way as the RTM, other than the carrying charge discussed later in my testimony. Thus, the deferral of the incremental costs and benefits of repowering would be similar and the accounting treatment would essentially be the same as the RTM. However, the delay in the collections from deferring the costs of repowering, rather than implementing an annual true-up mechanism, creates several problems.

Q. Please describe the problems associated with using a deferral instead of the RTM to track repowering costs and benefits.

A. First, the RTM ensures that costs and benefits are properly matched in the interim until the next rate case. The RTM will end when repowering costs are reflected in base rates (except for the tracking of the variability of PTCs). A deferral, on the other hand, would result in an amortization built into base rates that would not be removed until a future rate case.

Second, the RTM matches the costs and benefits so that the customers receiving the benefits are also paying the costs that generate the benefits. If the investment costs and PTCs are deferred, but the power cost benefits flow through the EBA, a mismatch occurs and customers receive a windfall in the near term. This violates the matching principle for costs and benefits. Because Mr. Thompson's deferral results in matching and intergenerational issues, I recommend using the RTM, which produces essentially the same result and avoids these issues. If Mr. Thomson's deferral approach is used, the net power cost benefits of the zero-cost energy must be pulled out of the EBA and deferred as well.

Third, generally accepted accounting principles do not allow for the deferral of a return on investment that would be collected at some undetermined time in the future. With the RTM, the collection of the return component happens annually as part of the RTM's regular true-up process. The deferral approach would have the same total overall impact on customers; however, it would lead to complicated separate accounting, increased difficulty in auditing, and delayed inclusion of cost/benefit impacts for both customers and the Company.

For these reasons, the RTM as proposed provides greater benefits to customers than the method described by Mr. Thomson.

Carrying Charge

Q. Mr. Thomson claims that the "Company has not provided support for using a 6% carrying charge rather than the Commission approved carrying charge method." (Thomson Direct, lines 156 - 157.) Why is the Company proposing a six percent carrying charge on the RTM during the deferral and collection period?

A. The repowered assets will provide customer benefits in two ways—by generating revenue through the PTCs and by reducing net power costs ("NPC") through zero-cost energy. The benefits of the reduced NPC will flow through the EBA, which includes a six percent carrying charge. To match the carrying charge used for the NPC benefits, the Company proposes that the same six percent carrying charge apply to the RTM.

Q. Mr. Thomson recommends that the Commission use an accounting order "without the interest carrying charges or sur-credits." (Thomson Direct, lines 171 - 172.) Is this a reasonable recommendation?

A. No. Mr. Thomson's recommendation is contrary to the carrying charge applied in the EBA and it is contrary to the carrying charge method he implies should be used for deferrals. Mr. Thomson does not explain the rationale for his proposal or justify its departure from established Commission precedent.

The use of no carrying charge, as proposed by Mr. Thomson, is unjustified given the customer benefits resulting from repowering. It is appropriate to apply a carrying charge to the balance of the RTM similar to the treatment afforded the EBA. As long as the Commission approves a reasonable carrying charge, however, the Commission could deviate from the carrying charge used for the EBA.

Operation and Maintenance ("O&M")

Q. Why is it necessary to include O&M expenses in the RTM?

A. The Company believes that, as part of the RTM, there needs to be a true-up of wind O&M associated with repowering. The Company has included O&M costs in its economic analysis supporting the decision to repower. O&M costs associated with the repowered wind turbines include increased wind lease payments and costs associated with Full Service Agreements from turbine vendors following repowering.

Q. What is the Company's position on using total wind O&M versus using non-labor O&M?

A. Ms. Ramas expressed concerns with tracking labor O&M expenses associated with the repowered assets. (Ramas Direct, lines 409 - 445.) The Company's proposal is a true-up of the total O&M associated with the wind facilities for simplicity and transparency. Because the increased O&M associated with wind repowering will mainly be associated with non-labor costs, however, the Company is not opposed to truing-up only the non-labor portion.

Q. Ms. Ramas is concerned about the Company's proposal to use a four-year historical average O&M expense, rather than the amount from the last rate case, to calculate the incremental O&M in the RTM. (Ramas Direct, lines 409 - 445.) Why did the Company propose a four-year historical average?

A. The intent of the RTM is to isolate the incremental costs of repowering and to match costs and benefits. To determine the incremental O&M costs, the Company used a pre-repowering four-year average expense as the baseline to determine the average O&M expense. To smooth annual fluctuations in O&M expenditures, a four-year average will minimize any anomalies.

Q. Is the Company changing the proposal for O&M as part of rebuttal?

A. No. The Company believes its original approach is the appropriate measurement of O&M for the RTM. However, the Company does not oppose using non-labor O&M in the RTM.

<u>Production Tax Credits</u>

Q. Why should the Commission approve the use of a mechanism to recover PTCs now, rather than in a future rate case as proposed by Ms. Ramas? (Ramas Direct, lines 361 - 363.)

A. Allowing recovery of the PTCs through the RTM better matches costs and benefits and ensures customers receive the benefits of repowering. The current PTCs included in base rates have already begun expiring, and the Company is not proposing to modify base rates to remove expiring PTCs. The Company is proposing to pass through 100 percent of the new PTC benefits through the RTM.

PTC benefits are tied to the output of the wind turbines. As the annual wind output varies, this results in changes to EBA-related NPC and PTCs associated with the wind production. The energy impact of wind production is captured in the EBA; therefore, the Company is proposing to capture the offsetting impact on PTCs in the RTM. This will match the benefits and costs associated with varying wind production. Also, as previously mentioned, customers will receive all of the PTC benefits associated with repowering.

Property Taxes

Q. Ms. Ramas criticizes the Company's proposal to use an average property tax rate from the past rate case in the RTM because it is inconsistent with projections of O&M expense from the last rate case. (Ramas Direct, lines 480 - 485.) Why did the Company propose using the average property tax rate from the last rate case?

A. The RTM measures the incremental costs and benefits associated with repowering assets. The baseline costs and benefits are set forth in Exhibit RMP___(JKL-1). For most items, the incremental impact can be measured using data outside of the last general rate case, *e.g.*, the incremental O&M expense discussed above. However, for purposes of quantifying the incremental impact on property taxes, the Company determined that using the average rate from the last rate case provided a verifiable and auditable measurement of the total-company property taxes included in rates. The property taxes are calculated assuming an incremental increase in property taxes resulting from an incremental increase in net rate base.

Q. Ms. Ramas is also critical of the Company's proposal to track only the incremental increase in property taxes, without accounting for the reduction associated with existing assets. (Ramas Direct, lines 504 - 508.) What is the Company's response to Ms. Ramas' assertion that the Company's proposal overstates property tax expense?

A. The Company's operating property is valued on a centralized basis in each of its states. Assessed values are a function of the Company's investment in operating property and the amount of earnings derived from the operation of such property. Even though a portion of the plant is being replaced, this will not directly reduce the Company's property tax expense. The method the Company is proposing is a reasonable method for estimating the property tax impact using the average rate from the last general rate case.

INTERGENERATIONAL EQUITY

Q. Mr. Peterson argues that the Company's proposal creates an intergenerational equity issue. (Peterson Direct, lines 177 - 178.) Do you agree?

A. No. Mr. Peterson focuses on what he describes as a "tipping point," after which customers will be burdened with the cost of the legacy equipment without any associated PTC benefits. This argument incorrectly suggests that PTC benefits are the sole benefits associated with repowering. Another significant benefit of repowering is incremental generation and extended asset life. This is covered in the netting of costs and benefits contemplated in the proposed RTM. This incremental generation is now anticipated to be approximately 743 gigawatt-hour ("GWhs") in each of the first

20 years and approximately 3,612 GWhs in each of the final 10 years. Thus, while the benefits of the PTCs will accrue to customers during the first 10 years, the repowered facilities will continue to provide customer benefits for their entire operating life, and will provide substantial value to customers in later years as a result of the increased generation associated with life extension.

Q. Are you suggesting that the NPC benefit of 743 GWhs of incremental generation during the 12-year period starting in 2028 will be commensurate with the costs projected to be borne by customers during the same period?

A. I am not. I think it is fair to highlight that there is a period during which customers will be subject to greater costs than benefits. The Company has been transparent on that point – although Mr. Link's exhibit RMP__(RTL-R3) shows the period lasting not 12, but five-to-six years in high natural gas price scenarios, six-to-seven years in medium natural gas price scenarios, and seven-to-nine years in low natural gas price scenarios. But the fact is that customers will receive *some* NPC benefit stemming from the replacement of the legacy equipment in every year of the repowered projects' lives. While that benefit may not exceed the associated costs in a given year, few regulators would suggest that a project may go forward only if it will produce benefits in excess of costs every single year of its decades-long life.

Throughout the lives of the repowered facilities, the replacement of the legacy equipment will create value through PTC benefits, incremental generation, or both. Therefore, it is inaccurate to claim that the Company's approach to cost recovery produces intergenerational inequity. As noted earlier in my testimony, however, DPU's proposal to defer the impacts of repowering rather than use the RTM does create intergenerational inequities because NPC benefits will immediately flow through the EBA, while the other costs and benefits would be deferred.

Q. Does it matter that the value of incremental generation may not exactly match the costs borne by future customers?

A. No. There will always be some fluctuation in the exact alignment of costs and benefits. As Dr. Bonbright notes, it is important to use a principled and standard approach to depreciation that does not shift or revise annual expense according to the exact value derived from a facility in a given year:

> [S]ince cost apportionments must be made ex ante, subject only to a minimum of midstream revisions, any correlation between the resulting annual charges imposed on consumers for capital costs (depreciation plus fair return plus taxes) and the relative benefits derived by consumers from the use of older assets as compared to newer assets, must be extremely rough. Hence, the choice of any given method of depreciation accounting must not be premised on any assumption of a close adherence to a relative-benefit standard.[3]

Q. What is the Company's position on the remedies identified by Mr. Peterson?

A. Mr. Peterson proposes two potential remedies: (1) accelerating the depreciation of the legacy equipment to match the 10-year PTC period; or (2) amortizing the PTC benefits over the full life of the legacy equipment. I agree with Mr. Peterson's estimation that either of these remedies *could* have the effect of reducing the project's overall benefits to customers. If parties, and ultimately the Commission, see merit in either approach, the Company does not necessarily object. The Company's support for such a change would be contingent upon the lifting of the RTM cap, however, as the number of years in which the RTM would produce a net cost to customers would certainly rise.

[3] James C. Bonbright, *Principles of Public Utility Rates*, 204 (Columbia University Press, 1961).

Q. What is your conclusion on the intergenerational equity argument?

A. While perfect matching of costs and benefits is ideal, it is only one of many considerations in the regulatory world. The Commission must also balance it with rate impacts on customers, simplicity in the regulatory accounting, and the unknown future of what might impact the cost of operating a specific asset. Based on this, I recommend the Commission amortize the PTCs over the period they are generated.

UPDATED RESULTS AND EXHIBITS

Q. As a result of the updates completed by Mr. Link and presented in his testimony, have you updated your exhibits from your direct testimony?

A. Yes.

Q. Please provide a summary of the updated results in the revised exhibits.

A. The revised exhibits incorporate modeling changes found in Mr. Link's updated analysis and rebuttal testimony. The revisions include Utah's allocated share of the updated wind construction cost, return, depreciation, PTCs, taxes, and operating costs and benefits. The updated net power cost changes associated with an updated load forecast, system dispatch and revised wind generation projections have been included in the EBA pass-through calculation. Figure 1 is a summary of the estimated repowering revenue requirement benefits found in the revised exhibits and shows a projected net customer benefit in each of the first four years, with net benefits of up to $12.4 million by 2022.

Figure 1

Repowering Estimated Revenue Requirement Cost (Benefit)
$thousands

		2019	2020	2021	2022
1	Total Company	(2,671)	(1,701)	(17,407)	(29,195)
2	Utah Allocated	(1,138)	(737)	(7,433)	(12,458)
3	Utah EBA	393	(4,661)	(5,306)	(5,530)
4	Utah Deferral	(1,531)	3,924	(2,127)	(6,928)
5	Net Customer Benefit	(1,138)	(737)	(7,433)	(12,458)

My original exhibits have been updated and are presented as RMP__(JKL-1R),[4] RMP__(JKL-2R), Exhibit RMP__(JKL-3R) and Exhibit RMP__(JKL-4R). These exhibits are revised with Mr. Link's updated economic analysis. They are in the same format to calculate the monthly and annual revenue requirements and RTM results as the exhibits presented in my direct testimony.

Q. What do the updated exhibits indicate regarding customer benefits and the RTM?

A. Exhibit RMP__(JKL-2R) shows that the wind repowering project provides estimated benefits each year. It also shows that the RTM passes these benefits on to customers each year, while allowing the Company to recover repowering project costs. Although the Company is proposing to cap[5] the RTM through the next general rate case, these updated results show a sufficient level of estimated repowering benefit that use of the RTM cap may not be necessary.

[4] Exhibit RMP__(JKL-1R), which provides a revenue requirement overview of the RTM, is changed to reference Mr. Hemstreet's revised exhibit, Confidential Exhibit RMP__(TJH-1R) in the NPC Savings Base calculation.

[5] The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers.

Exhibit RMP__(JKL-3R) shows the monthly calculations that roll-up to the annual results in Exhibit RMP__(JKL-2R). Exhibit RMP__(JKL-4R)[6] values have not changed from my direct testimony, but is included here to facilitate the referencing to key financial and allocation data used in the other exhibits.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[6] The reference to Confidential Exhibit RMP__TJH-3, page 2 of 2 has been updated to reflect that it has been replaced by Mr. Hemstreet's Confidential Exhibit RMP__TJH-1R.

Rocky Mountain Power
Exhibit RMP___(JKL-1R)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Jeffrey K. Larsen

Revenue Requirement Overview – Wind Repowering

October 2017

Resource Tracking Mechanism

Revenue Requirement Overview – Wind Repowering

<table>
<tr><th>Category</th><th>Base</th><th>New</th><th>Deferral</th></tr>
<tr><td>Capital Investment</td><td>Zero until the next general rate case. After rate case, the base will be the amount included in the test period, beginning on the rate effective date of that case.</td><td>Actual monthly plant in-service balances associated with wind repowering, beginning with first repowering assets placed in service.</td><td rowspan="7">The difference between the base and new columns will be included in the mechanism calculation until the amounts are fully included in a general rate case, at which time this will end.</td></tr>
<tr><td>Accumulated Depreciation Reserve</td><td>Same as capital investment.</td><td>Monthly depreciation reserve of repowered assets.</td></tr>
<tr><td>Accumulated Deferred Income Tax</td><td>Same as capital investment.</td><td>Actual accumulated deferred income tax balances associated with the repowering investment.</td></tr>
<tr><td>Operation & Maintenance Expense</td><td>Four-year average O&M expense for wind projects from 2014 to 2017, (2018-2019 are excluded to avoid any changes in O&M related to repowering).</td><td>Actual O&M expense for wind projects.</td></tr>
<tr><td>Depreciation Expense</td><td>Zero.</td><td>Actual monthly plant in-service balances associated with wind repowering less the base multiplied by current depreciation rates. The plant in service amounts used will be reduced by the replaced assets until the next depreciation study.</td></tr>
<tr><td>Property Taxes</td><td>Zero.</td><td>Capital Investment deferral less the Depreciation Reserve deferral multiplied by the average property tax rate from the last rate case.</td></tr>
<tr><td>Wind Tax</td><td>Zero.</td><td>Incremental energy production MWh associated with repowering multiplied by the wind tax rate.</td></tr>
<tr><td>NPC Savings</td><td>The EBA tracks and captures any incremental changes to wind production between NPC in base rates and actual NPC.
The base energy production = Actual energy produced by wind projects divided by (1 + percent of generation increase from Confidential Exhibit RMP__(TJH-1R)).</td><td>The EBA has a 100% pass through of the difference between base NPC and actual NPC. The RTM will capture any savings not included in the EBA related to incremental energy production associated with repowering, and pass these savings back to customers.</td><td>Any incremental wind production not in base rates will be multiplied by monthly HLH and LLH prices, (Mid-C for west and Four Corners for east resources) less wind integration costs.</td></tr>
<tr><td>PTC</td><td>Zero until next general rate case. After a rate case, the base will be the amount included in the test period, starting on the rate effective date, associated with repowering projects.</td><td>Actual MWh eligible for PTC produced by repowered wind plants multiplied by the production tax rate.</td><td>Difference between the base and actual. Tracked until repowering PTC’s have expired, and have been reset to zero in base rates.</td></tr>
<tr><td>RTM Cap</td><td>N/A</td><td colspan="2">The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers.</td></tr>
</table>

Rocky Mountain Power
Exhibit RMP___(JKL-2R)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Jeffrey K. Larsen

Example Annual RTM Deferral Calculation - Revenue Requirement

October 2017

Rocky Mountain Power
Exhibit RMP___(JKL-2R) Page 1 of 1
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

PacifiCorp
Utah
Wind Repowering - Example Annual RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			2019 Repowering				2020 Repowering				2021 Repowering				2022 Repowering			
			Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated
	Plant Revenue Requirement																	
1	Capital Investment	Footnote 1	164,461	SG	42.6283%	70,107	950,241	SG	42.6283%	405,072	1,086,036	SG	42.6283%	462,959	1,088,664	SG	42.6283%	464,079
2	Depreciation Reserve	Footnote 1	(896)	SG	42.6283%	(382)	(22,632)	SG	42.6283%	(9,648)	(56,758)	SG	42.6283%	(24,195)	(93,013)	SG	42.6283%	(39,650)
3	Accumulated DIT Balance	Footnote 1	(19,479)	SG	42.6283%	(8,304)	(183,873)	SG	42.6283%	(78,382)	(255,603)	SG	42.6283%	(108,959)	(296,492)	SG	42.6283%	(126,390)
4	Net Rate Base	sum of lines 1-3	144,085			61,421	743,736			317,042	773,675			329,804	699,159			298,040
5	Pre-Tax Rate of Return	line 34	10.649%			10.649%	10.649%			10.649%	10.649%			10.649%	10.649%			10.649%
6	Pre-Tax Return on Rate Base	line 4 * line 5	15,344			6,541	79,202			33,762	82,390			35,121	74,455			31,739
7	Wholesale Wheeling Revenue	Footnote 4	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-
8	Operation & Maintenance	Footnote 3	3,876	SG	42.6283%	1,652	12,113	SG	42.6283%	5,164	12,755	SG	42.6283%	5,437	9,590	SG	42.6283%	4,088
9	Depreciation	Footnote 3 & 6	8,120	SG	42.6283%	3,461	32,052	SG	42.6283%	13,663	36,213	SG	42.6283%	15,437	36,310	SG	42.6283%	15,478
10	Property Taxes	Footnote 3	-	GPS	42.4704%	-	7,237	GPS	42.4704%	3,074	8,032	GPS	42.4704%	3,411	7,773	GPS	42.4704%	3,301
11	Wind Tax	Footnote 3	92	SG	42.6283%	39	317	SG	42.6283%	135	395	SG	42.6283%	168	395	SG	42.6283%	168
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**27,432**			**11,694**	**130,922**			**55,798**	**139,785**			**59,575**	**128,522**			**54,775**
	Net Power Cost																	
13	NPC Incremental Savings	Footnote 3	921	SG	42.6283%	393	(10,934)	SG	42.6283%	(4,661)	(12,447)	SG	42.6283%	(5,306)	(12,973)	SG	42.6283%	(5,530)
	PTC Benefit																	
14	PTC Benefit	Footnote 3	(19,250)	SG	42.6283%	(8,206)	(75,507)	SG	42.6283%	(32,187)	(89,813)	SG	42.6283%	(38,286)	(89,813)	SG	42.6283%	(38,286)
15	PTC Benefit in Base Rates	Footnote 3	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-
16	Net PTC	sum of lines 14 and 15	(19,250)			(8,206)	(75,507)			(32,187)	(89,813)			(38,286)	(89,813)			(38,286)
17	Gross- up for taxes	line 16 * (line 32 - 1)	(11,774)			(5,019)	(46,182)			(19,687)	(54,932)			(23,417)	(54,932)			(23,417)
18	PTC Revenue Requirement	sum of lines 16 and 17	(31,023)			(13,225)	(121,689)			(51,874)	(144,745)			(61,702)	(144,745)			(61,702)
19	**Rev. Requirement**	sum of lines 12, 13, 18	(2,671)			(1,138)	(1,701)			(737)	(17,407)			(7,433)	(29,195)			(12,458)
	Adjustment for EBA Pass-through																	
20	NPC Incremental Savings	line 13				393				(4,661)				(5,306)				(5,530)
21	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%				100%				100%
22	EBA Pass-through	line 20 * line 21				393				(4,661)				(5,306)				(5,530)
23	**Rev. Reqt. after EBA Pass-through**	line 19 - line 22				(1,531)				3,924				(2,127)				(6,928)
24	**Total Deferral - UT Share**	Footnote 5				(1,531)				3,924				(2,127)				(6,928)
25	**Net Customer Benefit**	line 22 + line 24				(1,138)				(737)				(7,433)				(12,458)
	Deferral Balance - UT Share																	
26	Beginning Deferral Balance	line 30 of previous year				-				(1,606)				3,473				(277)
27	Monthly Deferral	Footnote 5				(1,531)				3,924				(2,127)				(6,928)
28	Deferral Collection	Footnote 3				-				1,071				(1,780)				(973)
29	Carrying Charge	Footnote 3				(75)				84				157				(266)
30	**Ending Deferral Balance**	sum of lines 26-29				(1,606)				3,473				(277)				(8,444)
31	Federal/State Combined Tax Rate	JKL_4R, line 5	37.951%															
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4R, line 6	1.6116															
33	Deferred Balance Carrying Charge	Footnote 2	6.00%	EBA carrying charge rate under Electric Service Schedule 94														
34	Pretax Return	JKL_4R, line 4	10.649%	13-035-184 Capital Structure & Cost - Ordered														
35	Property Tax Rate	JKL_4R, line 14	0.77%	Property Tax Expense as a percent of Net plant from 13-035-184														
36	Utah SG Factor	JKL_4R, line 15	42.6283%															
37	Utah GPS Factor	JKL_4R, line 16	42.4704%															

Footnotes:
1) Capital balances equal the average of the monthly balances in JKL-3 with a one month delay
2) Carrying Charge (line 29) is applied to average monthly deferral balances
3) Equals the sum of each year's monthly values in JKL-3
4) Not Applicable for Repowering
5) The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers
6) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

Rocky Mountain Power
Exhibit RMP___(JKL-3R)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Jeffrey K. Larsen

Example Monthly RTM Deferral Calculation - Revenue Requirement

October 2017

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		-	-	-	-	-	-	145,625	145,625	145,625	587,127	949,528	949,528
2	Depreciation Reserve		-	-	-	-	-	-	(405)	(809)	(1,214)	(2,844)	(5,482)	(8,120)
3	Accumulated DIT Balance		-	-	-	-	-	-	(11,912)	(11,912)	(17,868)	(73,171)	(118,889)	(158,519)
4	Net Rate Base	sum of lines 1-3	-	-	-	-	-	-	133,309	132,904	126,544	511,111	825,156	782,889
5	Pre-Tax Rate of Return	line 34	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%
6	Pre-Tax Return on Rate Base	Footnote 1	-	-	-	-	-	-	-	1,183	1,179	1,123	4,536	7,323
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		-	-	-	-	-	-	324	621	713	754	716	748
9	Depreciation	Footnote 5	-	-	-	-	-	-	405	405	405	1,631	2,638	2,638
10	Property Taxes	Prior December (line 1 + line 2) x line 35	-	-	-	-	-	-	-	-	-	-	-	-
11	Wind Tax		-	-	-	-	-	-	8	15	17	18	17	18
12	**Total Plant Revenue Requirement**	sum of lines 6-11	-	-	-	-	-	-	736	2,223	2,314	3,526	7,907	10,726
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	-	-	-	-	-	-	77	147	170	179	170	178
	PTC Benefit													
14	PTC Benefit		-	-	-	-	-	-	(1,608)	(3,083)	(3,544)	(3,745)	(3,557)	(3,714)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	-	-	-	-	-	-	(1,608)	(3,083)	(3,544)	(3,745)	(3,557)	(3,714)
17	Gross- up for taxes	line 16 * (line 31 - 1)	-	-	-	-	-	-	(983)	(1,886)	(2,167)	(2,290)	(2,175)	(2,271)
18	PTC Revenue Requirement	sum of line 16 and 17	-	-	-	-	-	-	(2,591)	(4,969)	(5,711)	(6,035)	(5,732)	(5,985)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	-	-	-	-	-	-	(1,778)	(2,598)	(3,227)	(2,330)	2,345	4,918
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	-	-	-	-	-	-	77	147	170	179	170	178
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	-	-	-	-	-	-	77	147	170	179	170	178
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	-	-	-	-	-	-	(1,855)	(2,746)	(3,397)	(2,509)	2,175	4,741
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	-	-	-	-	-	-	(791)	(1,170)	(1,448)	(1,070)	927	2,021
25	**Net Customer Benefit**	line 22 * line 36 + line 24	-	-	-	-	-	-	(758)	(1,108)	(1,376)	(993)	1,000	2,097
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	-	-	-	-	-	-	-	(793)	(1,970)	(3,432)	(4,521)	(3,614)
27	Monthly Deferral	line 24	-	-	-	-	-	-	(791)	(1,170)	(1,448)	(1,070)	927	2,021
28	Deferral Collection	Footnote 3	-	-	-	-	-	-	-	-	-	-	-	-
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	-	-	-	-	-	-	(2)	(7)	(13)	(20)	(20)	(13)
30	**Ending Deferral Balance**	sum of lines 26-29	-	-	-	-	-	-	(793)	(1,970)	(3,432)	(4,521)	(3,614)	(1,606)
31	Federal/State Combined Tax Rate	JKL_4R, line 5	37.951%											
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4R, line 6	1.6116											
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2R line 33	6.00%											
34	Pretax Return	JKL_4R, line 4	10.649%											
35	Property Tax Rate	JKL_4R, line 14	0.77%											
36	Utah SG Factor	JKL_4R, line 15	42.6283%											
37	Utah GPS Factor	JKL_4R, line 16	42.4704%											

Footnotes:
1) Pre-tax Return, line 6, is calculated as the rate of return (line 5) multiplied by the ending net rate base of the prior month (line 4) divided by 12
2) Not Applicable for Repowering
3) For illustrative purposes, collection of December's balance is assumed to be collected beginning the following May 1
4) The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the
wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers
5) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		949,528	949,528	949,528	949,528	949,528	949,528	951,240	951,240	951,240	951,240	951,240	1,085,025
2	Depreciation Reserve		(10,757)	(13,395)	(16,032)	(18,670)	(21,307)	(23,945)	(26,588)	(29,230)	(31,873)	(34,515)	(37,158)	(40,172)
3	Accumulated DIT Balance		(158,519)	(158,519)	(175,421)	(175,421)	(175,421)	(192,324)	(192,324)	(192,324)	(209,226)	(209,226)	(209,226)	(236,714)
4	Net Rate Base	sum of lines 1-3	780,251	777,614	758,074	755,437	752,799	733,259	732,329	729,686	710,141	707,499	704,856	808,139
5	Pre-Tax Rate of Return	line 34	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%
6	Pre-Tax Return on Rate Base	Footnote 1	6,948	6,924	6,901	6,727	6,704	6,681	6,507	6,499	6,475	6,302	6,279	6,255
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		904	913	1,047	1,065	1,035	976	1,002	928	997	1,105	1,053	1,089
9	Depreciation	Footnote 5	2,638	2,638	2,638	2,638	2,638	2,638	2,642	2,642	2,642	2,642	2,642	3,014
10	Property Taxes	Prior December (line 1 + line 2) x line 35	603	603	603	603	603	603	603	603	603	603	603	603
11	Wind Tax		24	24	27	28	27	26	26	24	26	29	28	29
12	**Total Plant Revenue Requirement**	sum of lines 6-11	11,116	11,102	11,216	11,061	11,007	10,922	10,781	10,697	10,745	10,682	10,605	10,990
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	(816)	(824)	(945)	(961)	(934)	(881)	(904)	(838)	(900)	(998)	(951)	(983)
	PTC Benefit													
14	PTC Benefit		(5,635)	(5,690)	(6,525)	(6,636)	(6,453)	(6,081)	(6,244)	(5,784)	(6,217)	(6,890)	(6,565)	(6,787)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(5,635)	(5,690)	(6,525)	(6,636)	(6,453)	(6,081)	(6,244)	(5,784)	(6,217)	(6,890)	(6,565)	(6,787)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(3,446)	(3,480)	(3,991)	(4,059)	(3,947)	(3,720)	(3,819)	(3,538)	(3,802)	(4,214)	(4,015)	(4,151)
18	PTC Revenue Requirement	sum of line 16 and 17	(9,081)	(9,171)	(10,516)	(10,695)	(10,399)	(9,801)	(10,062)	(9,322)	(10,019)	(11,104)	(10,580)	(10,938)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	1,219	1,107	(245)	(596)	(327)	241	(186)	537	(175)	(1,420)	(926)	(931)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(816)	(824)	(945)	(961)	(934)	(881)	(904)	(838)	(900)	(998)	(951)	(983)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(816)	(824)	(945)	(961)	(934)	(881)	(904)	(838)	(900)	(998)	(951)	(983)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	2,035	1,931	700	365	608	1,121	718	1,374	725	(422)	25	52
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	867	822	297	155	258	477	305	585	308	(181)	10	21
25	**Net Customer Benefit**	line 22 * line 36 + line 24	519	471	(105)	(255)	(140)	102	(80)	228	(75)	(606)	(396)	(398)
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	(1,606)	(746)	75	373	530	925	1,542	1,989	2,719	3,175	3,143	3,302
27	Monthly Deferral	line 24	867	822	297	155	258	477	305	585	308	(181)	10	21
28	Deferral Collection	Footnote 3	-	-	-	-	134	134	134	134	134	134	134	134
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	(6)	(2)	1	2	3	5	8	11	14	15	15	16
30	**Ending Deferral Balance**	sum of lines 26-29	(746)	75	373	530	925	1,542	1,989	2,719	3,175	3,143	3,302	3,473
31	Federal/State Combined Tax Rate	JKL_4R, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4R, line 6												
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2R line 33												
34	Pretax Return	JKL_4R, line 4												
35	Property Tax Rate	JKL_4R, line 14												
36	Utah SG Factor	JKL_4R, line 15												
37	Utah GPS Factor	JKL_4R, line 16												

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		1,085,025	1,085,025	1,085,025	1,085,025	1,085,025	1,085,025	1,087,451	1,087,451	1,087,451	1,087,451	1,087,451	1,087,451
2	Depreciation Reserve		(43,186)	(46,200)	(49,214)	(52,228)	(55,242)	(58,256)	(61,278)	(64,299)	(67,320)	(70,342)	(73,363)	(76,384)
3	Accumulated DIT Balance		(236,714)	(236,714)	(249,307)	(249,307)	(249,307)	(261,899)	(261,899)	(261,899)	(274,491)	(274,491)	(274,491)	(287,083)
4	Net Rate Base	sum of lines 1-3	805,125	802,111	786,505	783,490	780,476	764,870	764,275	761,253	745,640	742,619	739,597	723,984
5	Pre-Tax Rate of Return	line 34	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%
6	Pre-Tax Return on Rate Base	Footnote 1	7,172	7,145	7,118	6,980	6,953	6,926	6,788	6,782	6,756	6,617	6,590	6,563
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		1,063	1,063	1,063	1,063	1,063	1,063	1,063	1,063	1,063	1,063	1,063	1,063
9	Depreciation	Footnote 5	3,014	3,014	3,014	3,014	3,014	3,014	3,021	3,021	3,021	3,021	3,021	3,021
10	Property Taxes	Prior December (line 1 + line 2) x line 35	669	669	669	669	669	669	669	669	669	669	669	669
11	Wind Tax		33	33	33	33	33	33	33	33	33	33	33	33
12	**Total Plant Revenue Requirement**	sum of lines 6-11	11,951	11,924	11,897	11,759	11,732	11,705	11,574	11,569	11,542	11,404	11,377	11,350
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)
	PTC Benefit													
14	PTC Benefit		(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)
18	PTC Revenue Requirement	sum of line 16 and 17	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	(1,148)	(1,175)	(1,202)	(1,340)	(1,367)	(1,394)	(1,525)	(1,530)	(1,557)	(1,696)	(1,723)	(1,749)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)	(1,037)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	(111)	(138)	(165)	(303)	(330)	(357)	(488)	(493)	(520)	(659)	(685)	(712)
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	(48)	(60)	(71)	(130)	(142)	(153)	(209)	(211)	(223)	(282)	(293)	(305)
25	**Net Customer Benefit**	line 22 * line 36 + line 24	(491)	(502)	(513)	(572)	(584)	(595)	(651)	(653)	(665)	(724)	(735)	(747)
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	3,473	3,576	3,667	3,748	3,769	3,357	2,932	2,448	1,960	1,458	894	316
27	Monthly Deferral	line 24	(48)	(60)	(71)	(130)	(142)	(153)	(209)	(211)	(223)	(282)	(293)	(305)
28	Deferral Collection	Footnote 3	134	134	134	134	(289)	(289)	(289)	(289)	(289)	(289)	(289)	(289)
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	17	17	18	18	19	17	15	12	10	7	4	2
30	**Ending Deferral Balance**	sum of lines 26-29	3,576	3,667	3,748	3,769	3,357	2,932	2,448	1,960	1,458	894	316	(277)
31	Federal/State Combined Tax Rate	JKL_4R, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4R, line 6												
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2R line 33												
34	Pretax Return	JKL_4R, line 4												
35	Property Tax Rate	JKL_4R, line 14												
36	Utah SG Factor	JKL_4R, line 15												
37	Utah GPS Factor	JKL_4R, line 16												

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		1,087,451	1,087,451	1,087,451	1,087,451	1,087,451	1,087,451	1,090,362	1,090,362	1,090,362	1,090,362	1,090,362	1,090,362
2	Depreciation Reserve		(79,406)	(82,427)	(85,448)	(88,470)	(91,491)	(94,512)	(97,543)	(100,573)	(103,603)	(106,633)	(109,664)	(112,694)
3	Accumulated DIT Balance		(287,083)	(287,083)	(293,356)	(293,356)	(293,356)	(299,629)	(299,629)	(299,629)	(305,902)	(305,902)	(305,902)	(312,175)
4	Net Rate Base	sum of lines 1-3	720,963	717,941	708,647	705,626	702,604	693,310	693,191	690,161	680,857	677,827	674,797	665,493
5	Pre-Tax Rate of Return	line 34	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%	10.649%
6	Pre-Tax Return on Rate Base	Footnote 1	6,425	6,398	6,371	6,289	6,262	6,235	6,153	6,152	6,125	6,042	6,015	5,988
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		799	799	799	799	799	799	799	799	799	799	799	799
9	Depreciation	Footnote 5	3,021	3,021	3,021	3,021	3,021	3,021	3,030	3,030	3,030	3,030	3,030	3,030
10	Property Taxes	Prior December (line 1 + line 2) x line 35	648	648	648	648	648	648	648	648	648	648	648	648
11	Wind Tax		33	33	33	33	33	33	33	33	33	33	33	33
12	**Total Plant Revenue Requirement**	sum of lines 6-11	10,926	10,899	10,872	10,790	10,763	10,736	10,663	10,662	10,635	10,552	10,525	10,498
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)
	PTC Benefit													
14	PTC Benefit		(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)	(7,484)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)	(4,578)
18	PTC Revenue Requirement	sum of line 16 and 17	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)	(12,062)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	(2,217)	(2,244)	(2,271)	(2,353)	(2,380)	(2,407)	(2,480)	(2,481)	(2,508)	(2,591)	(2,618)	(2,645)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)	(1,081)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	(1,136)	(1,163)	(1,190)	(1,272)	(1,299)	(1,326)	(1,399)	(1,400)	(1,427)	(1,510)	(1,537)	(1,564)
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	(485)	(497)	(508)	(543)	(555)	(566)	(598)	(598)	(609)	(645)	(656)	(668)
25	**Net Customer Benefit**	line 22 * line 36 + line 24	(946)	(958)	(969)	(1,004)	(1,016)	(1,027)	(1,058)	(1,059)	(1,070)	(1,105)	(1,117)	(1,128)
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	(277)	(1,053)	(1,845)	(2,653)	(3,499)	(4,050)	(4,615)	(5,214)	(5,816)	(6,433)	(7,089)	(7,759)
27	Monthly Deferral	line 24	(485)	(497)	(508)	(543)	(555)	(566)	(598)	(598)	(609)	(645)	(656)	(668)
28	Deferral Collection	Footnote 3	(289)	(289)	(289)	(289)	23	23	23	23	23	23	23	23
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	(2)	(6)	(10)	(14)	(19)	(22)	(25)	(28)	(31)	(34)	(37)	(41)
30	**Ending Deferral Balance**	sum of lines 26-29	(1,053)	(1,845)	(2,653)	(3,499)	(4,050)	(4,615)	(5,214)	(5,816)	(6,433)	(7,089)	(7,759)	(8,444)
31	Federal/State Combined Tax Rate	JKL_4R, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4R, line 6												
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2R line 33												
34	Pretax Return	JKL_4R, line 4												
35	Property Tax Rate	JKL_4R, line 14												
36	Utah SG Factor	JKL_4R, line 15												
37	Utah GPS Factor	JKL_4R, line 16												

Total Plant Revenue Requirement (Lines 1 - 12, 34):

Exhibit JKL-3R shows the calculation of the RTM revenue requirement deferral described in my testimony. The calculation starts with total Company amounts on lines 1 - 23 to calculate the Utah specific amounts on lines 24 - 30. To calculate the return on rate base associated with the wind repowering investment, net rate base associated with the repowered wind resources is calculated on a monthly basis. The net rate base balance on line 4 includes the investment in repowered wind resources, along with the associated impacts on the depreciation reserve and accumulated DIT Balance. The monthly beginning net rate base (the final amount from the prior month) is then multiplied by the pre-tax Weighted Average Cost of Capital ("WACC") from the last Utah general rate case on line 5 to determine the Company's pre-tax return on rate base on line 6. The example uses the pre-tax WACC from Docket No. 09-035-15. The total plant revenue requirement is calculated by taking the return on rate base shown on line 6 and adding the O&M expense, depreciation expense, property taxes and wind tax on lines 8 - 11 to determine the total plant revenue requirement on line 12. Wholesale wheeling revenue on line 7 is not used for wind repowering, but is needed for a similar calculation for the Gateway transmission and wind expansion project.

Net Power Costs (Line 13):

The total company incremental NPC savings associated with repowered wind resources is shown on line 13. The incremental NPC savings associated with the repowered wind projects are multiplied by one hundred percent on line 21 to determine the amount of the NPC savings that will be returned to customers through the sharing band of the EBA. The calculation of NPC savings is described in Exhibit JKL-4R.

PTC Benefits (Lines 14-18, 31, 32):

Lines 14-18 show the calculation of the PTC benefits associated with the repowered wind resources. The actual PTC sales are grossed-up for taxes using the net-to-gross bump-up factor from the Company's last general rate case (shown on line 32) to derive the PTC revenue requirement on line 18. The tax gross-up is necessary for customers to get the full revenue requirement benefit of the PTCs and is calculated using the federal and state combined tax rate shown on line 31, which was also included in the last general rate case.

Deferral Balance (Lines 19 – 30):

The Utah share of the net deferral begins by calculating the total repowering project revenue requirement on line 19, which is the sum of Total Plant Revenue Requirement on line 12, NPC Incremental Savings on line 13, and PTC Revenue Requirement on line 18. The EBA pass-through on line 22 is subtracted to provide the Revenue Requirement after EBA Pass-through on line 23. Utah's share of the Total Deferral is dependent upon the amount of revenue requirement cost or benefit that is determined in a particular year. If the Revenue Requirement after EBA Pass-through for any year on line 23 is negative, which means that the repowering project provides a revenue requirement benefit greater than the benefit being passed through the EBA, then that year's deferral is equal to the additional benefit found on line 23. If the Revenue Requirement after EBA Pass-through for any year on line 23 is positive, the Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers. The Net Customer Benefit (line 25) is the sum of the EBA Pass-through (line 22) and the Total Deferral - Utah Share (line 24). The carrying charge, shown on line 29 is calculated using the Commission-authorized rate on line 33 and is consistent with the calculations used in the Company's other mechanisms such as the EBA. As described earlier, each month the total-Company RTM revenue requirement will be calculated as illustrated on Exhibit JKL-3 to align with the resources included in the EBA. Once per year on a calendar-year basis, the Company will sum the monthly RTM revenue requirement entries to prepare the annual RTM application for filing with the Commission on March15, with an interim rate effective date that corresponds with the EBA application, May 1.

Rocky Mountain Power
Exhibit RMP___(JKL-4R)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Jeffrey K. Larsen

Capital Structure, Property Tax Rate and Net Power Cost Description

October 2017

PacifiCorp
Utah
Wind Repowering - Capital Structure, Property Tax and Net Power Cost Description
Capital Structure and Property Tax Rate

13-035-184 Capital Structure & Cost
Effective 9/1/2014

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Pre-Tax Cost
1	Debt	48.556%	5.200%	2.525%	2.525%
2	Preferred	0.016%	6.753%	0.001%	0.002%
3	Common	51.428%	9.800%	5.040%	8.123%
4			**TOTAL**	**7.566%**	**10.649%**
5	Consolidated Tax Rate		37.951%		
6	Tax Gross-up factor for PTC = (1/(1 - tax rate))		1.6116		
	Property Tax Calculation as filed in Docket Number 13-035-184				
7	Total Company				134,961,526
8	Utah GPS Factor				42.4704%
9	Utah Property Taxes				57,318,700
10	Utah Gross EPIS				10,912,081,614
11	Utah Accum. Depr.				(3,234,910,020)
12	Utah Accum. Amort.				(221,249,967)
13	Utah Net EPIS				7,455,921,626
14	Estimated Utah Property Tax Rate				0.769%
15	Utah SG Factor - Docket No. 13-035-184				42.6283%
16	Utah GPS Factor - Docket No. 13-035-184				42.4704%

Net Power Cost Incremental Savings Calculation and Definitions

Incremental Generation = Wind Plant Generation MWh – Base Wind Plant Generation MWh

Base Wind Plant Generation = Wind Plant Generation MWh / (1 + Project Generation Increase %)

$$NPC\ Incremental\ Savings = [Incremental\ Gen_{HLH} \times (Monthly\ Market\ Price_{HLH} - Integration\ Costs)] + [Incremental\ Gen_{LLH} \times (Monthly\ Market\ Price_{LLH} - Integration\ Costs)]$$

$$RTM\ NPC\ Benefit = NPC\ Incremental\ Savings \times ECAM\ Sharing\ Band$$

Where:

Incremental Generation = The increase in generation at the wind plant due to repowering
Project Generation Increase % = The percentage change in energy at the wind plant due to repowering (See Confidential Exhibit RMP__TJH-1R)
$Incremental\ Gen_{HLH}$ = *The increase in generation at the wind plant due to repowering during heavy load hours*
$Incremental\ Gen_{LLH}$ = *The increase in generation at the wind plant due to repowering during light load hours*
$Monthly\ Market\ Price_{HLH}$ = *Heavy load hour monthly market price*
$Monthly\ Market\ Price_{LLH}$ = *Light load hour monthly market price*
Integration Costs = Wind integration costs from the most recent IRP
RTM NPC Benefit = The NPC repowering benefit absorbed by the Company in the ECAM as a result of the sharing band

Rocky Mountain Power
Docket No. 17-035-39
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Nikki L. Kobliha

October 2017

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

A. My name is Nikki L. Kobliha and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Vice President, Chief Financial Officer and Treasurer for PacifiCorp. I am testifying on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Business Administration with a concentration in Accounting from the University of Portland in 1994. I became a certified public accountant in 1996. I joined the Company in 1997 and have taken on roles of increasing responsibility before being appointed Chief Financial Officer in 2015.

Q. What are your responsibilities as Vice President, Chief Financial Officer and Treasurer?

A. I am responsible for all aspects of the Company's finance, accounting, income tax, internal audit, Securities and Exchange Commission reporting, treasury, credit risk management, pension, and other investment management activities.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

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

A. In support of the Company's request that the Public Service Commission of Utah ("Commission") approve its energy resource decision for wind repowering, my testimony responds to the tax issues raised in the direct testimonies of Division of Public Utilities ("DPU") witness Mr. Daniel Peaco, Office of Consumer Services ("OCS") witnesses Mr. Gavin Mangelson, Mr. Philip Hayet, and Ms. Donna Ramas, and Utah Association of Energy Users ("UAE") witness Mr. Kevin C. Higgins.

I provide a brief summary of the requirements that the Company must satisfy for the repowered wind facilities to qualify for 100 percent of the federal production tax credits ("PTCs"). I respond to specific issues raised by DPU, OCS, and UAE, and I demonstrate that the Company has carefully managed the PTC-related risks associated with the wind repowering project to ensure that the facilities qualify for 100 percent of the PTC value. Specifically, I address the following:

- How the Company's safe-harbor wind-turbine components purchased in 2016 are sufficient to qualify the wind repowering project for 100 percent of the value of available PTCs under the five-percent safe-harbor test;
- How the Company will meet the continuous construction requirement; and
- How the Company will meet the 80/20 test for repowered wind facilities.

In addition, I describe the Company's current high-level view of the likelihood of tax reform, which provides the basis for Company witness Mr. Rick T. Link's tax-related sensitivity analysis. This analysis shows that the wind repowering project still provides a significant benefit to customers even with a major reduction in the corporate tax rate.

Q. Please summarize your testimony.

A. The customer benefits of the wind repowering project are demonstrated in the economic analysis presented by Mr. Link. Because the project economics rely heavily on tax benefits, the Company's due diligence involves thorough consideration of all the tax-related risks associated with repowering.

The Company took a number of steps to ensure that the safe-harbor equipment purchased in 2016 was sufficient to qualify the repowered facilities for 100 percent of the PTC benefits. The Company can further mitigate any risks associated with the safe-harbor purchases by transferring safe-harbor equipment among facilities and affiliates to ensure that the customer benefits are maximized.

To minimize risks associated with the 80/20 test, which requires that the new equipment installed represent at least 80 percent of the overall facility costs, the Company has reasonably engaged a third-party expert firm to value the retained equipment. Based on that valuation, and the fact that the value of the new equipment will be known, the Company has largely mitigated the risk that the new projects will not meet the 80/20 rule.

Finally, at this point, a change in the federal corporate income tax rate is highly uncertain and, under the most likely compromise outcome, the change is unlikely to eliminate the customer benefits. Moreover, any tax rate change will likely be known by early 2018, before the Company moves forward with the wind repowering project. Thus, the Company will evaluate changes in tax law as part of its overall reassessment of the project economics before committing to repowering.

BACKGROUND

Q. Please describe how a PTC is generated.

A. The Internal Revenue Code ("IRC") provides that a wind facility will generate a PTC equal to an inflation-adjusted 1.5 cents per kilowatt hour of electricity that is produced and sold to a third-party for a period of 10 years commencing with the date the facility is placed in service for income tax purposes. The current inflation-adjusted PTC rate for electricity generated in 2017 is 2.4 cents per kilowatt hour.

Q. Under current income tax law, the PTC is being phased out. Please explain the phase-out process.

A. The Protecting Americans from Tax Hikes Act of 2015 ("PATH Act") was signed into law on December 18, 2015, and retroactively extended and phased out the PTC for wind facilities that began construction before January 1, 2020. For a wind facility that began construction before January 1, 2017, the credit generated by the wind facility is a full 100 percent of the PTC. For a wind facility that begins construction in 2017, the credit is reduced by 20 percent (*i.e.*, the facility receives 80 percent of the full PTC). For a wind facility that begins construction in 2018, the credit is reduced by 40 percent (*i.e.*, the facility receives 60 percent of the full PTC). For a wind facility that begins construction in 2019, the credit is reduced by 60 percent (*i.e.*, the facility receives 40 percent of the full PTC). For a wind facility that begins construction after December 31, 2019, there is no PTC available.

Q. When does "construction" begin for a wind facility?

A. Internal Revenue Service ("IRS") Notice 2013-29 provides a taxpayer with two methods to establish that construction of a wind facility has begun. First, the taxpayer can begin physical work of a significant nature. Physical work can include both on-site and off-site work, either performed by the taxpayer or by another person subject to a binding contract.

Second, a taxpayer can pay or incur five percent or more of the eventual total cost of the qualified wind facility. This is known as the five-percent safe harbor. The Company is using this five-percent safe-harbor method to qualify for 100 percent of the PTC. The Company purchased and took delivery and title to sufficient wind turbine components in December 2016 to meet the five-percent safe harbor and to show that physical construction of the wind facilities that will be repowered began before January 1, 2017, and thus qualify the repowered facilities for 100 percent of the PTC.

In addition to the requirement that the wind facility begin construction before January 1, 2017, to qualify for 100 percent of the PTC, the wind facility must also satisfy the continuity-of-construction requirement.

Q. Please explain the continuity-of-construction requirement.

A. The wind facility must be under continuous construction from the time physical construction begins until the wind facility is placed in service. Whether a taxpayer satisfies the continuity-of-construction requirement is determined based on the relevant facts and circumstances surrounding the timing of the physical work to be performed on the wind facility. The IRS has issued limited guidance on what facts and circumstances might be considered to meet this requirement. For example, the IRS has provided a list of non-exclusive "excusable" disruptions and delays deemed to be beyond the control of the taxpayer and therefore acceptable reasons that would support the taxpayer's contention that it has maintained a continuous program of construction. These acceptable delays include weather-caused delays, permit delays outside of the control of the taxpayer, and supply shortages, among others.

The IRS has, however, also created a continuity-of-construction safe harbor (the "calendar safe harbor"). If a taxpayer places a facility in service by the end of a calendar year that is not more than four calendar years after the calendar year during which construction of the wind facility began, the facility will satisfy the continuous-construction requirement by virtue of the calendar safe harbor. Accordingly, if construction of a wind facility began in December 2016, as long as the facility is placed in service by December 31, 2020, the facility will meet the continuity-of-construction requirement.

The Company will have all repowered wind facilities placed in service by December 31, 2020, and therefore will qualify for the 100 percent PTC under the four-year calendar safe harbor.

Q. Are there other requirements that must be met for the repowered wind facilities to qualify for PTCs?

A. Yes. The repowered wind facilities must meet the IRS 80/20 test to qualify for PTCs.

Q. What is the IRS "80/20" test?

A. A repowered wind facility may qualify as a new asset and originally placed in service for purposes of starting a new 10-year PTC-production period even if it contains some used property, provided the fair market value of the used property is no more than 20 percent of the facility's total value (the cost of the new property plus the value of the used property).

PTC RISK CONSIDERATIONS

Q. DPU witness Mr. Peaco raises the concern that for some of the Company's facilities being repowered, the Company may have purchased insufficient equipment to qualify under the five-percent safe harbor if there are cost overruns. (Peaco Direct, lines 653 - 667.) Do you believe that this is a material risk?

A. No. As described in the rebuttal testimony of Company witness Mr. Timothy J. Hemstreet, the Company's due diligence included extensive analysis to ensure that the Company will meet the five-percent safe-harbor test at each facility.

In addition, IRS rules allow the Company to purchase and transfer 2016 safe-harbor equipment from one of its Berkshire Hathaway Energy affiliates—MidAmerican Energy Company or Berkshire Hathaway Energy Renewables. Transfer of PTC safe-harbor equipment among the affiliates within a consolidated taxpayer is allowed, and the transferred equipment retains the ability to be used as safe-harbor equipment for PTC qualification.

Finally, the five-percent safe-harbor test is not an all-or-nothing test. Qualifying five-percent safe-harbor wind-turbine components ("PTC Components") can be used to meet the five-percent safe-harbor test for individual turbines until they are exhausted when the total project costs of those individual repowered turbines exceeds 20 times the safe-harbor amount. For example, if, as a result of cost overruns, the Company only has enough PTC Components available to qualify 65 out of 66 turbines at a repowered wind facility, instead of all 66, the Company would allocate the PTC Components as necessary to cover the costs of 65 of the turbines and would use newly acquired equipment to repower the remaining turbine. The Company would then have 65 repowered turbines that qualify for 100 percent PTC and only one that does not.

Q. Mr. Peaco also cites permitting and financing risks that could delay these project and threaten their ability to qualify for PTCs. (Peaco Direct, lines 692 - 695.) Are these risks material?

A. No. As discussed in Mr. Hemstreet's rebuttal testimony, there is no material risk due to any permitting delay because most of the facilities to be repowered are already approved and the others are expected to have no issues.

Regarding financing risks, the Company credit rating is more than sufficient to provide financing at commercially reasonable terms, and neither General Electric International, Inc. (“GE”) nor Vestas-American Wind Technology, Inc. (“Vestas”) have raised any issues about the Company’s ability to financially perform under the contracts.

Q. Turning to the 80/20 test, Mr. Peaco argues that the Company has not performed any analysis of the risks of not meeting this requirement. (Peaco Direct, lines 738 - 741.) Is this a fair criticism?

A. No. Mr. Peaco identifies two types of risk related to qualifying under the 80/20 test: the risk that “the Company’s interpretation of the fair market value of the retained components is not accepted by the IRS;” and the risk that “if the costs of the repowering are less than expected, the new equipment might not comprise 80% of the value of the facility.” (Peaco Direct, lines 732 - 735.)

To address the first risk, the Company engaged Ernst and Young LLP to provide an independent determination of the fair market value (“FMV”) of the retained components (*e.g.*, the tower and foundation of the wind turbine generator (“WTG”)) at each wind facility that will remain in place and be reused in connection with the repowering initiative. Ernst and Young LLP is a qualified independent appraiser who will apply Uniform Standards of Professional Appraisal Practice (“USPAP”) in measuring the FMV of the retained components. Ernst and Young LLP has indicated that rate base amount (*i.e.*, the net book value of the retained components reduced by the accumulated deferred income taxes) can be a key determinant of the FMV for property owned by a regulated enterprise, a conclusion with which the Company agrees, based on the experiences of its affiliates in dealing with the IRS on other valuations of public utility property.

Ernst and Young LLP has provided preliminary values, which will be finalized in the final valuation reports that will be issued contemporaneously with the in-service date of the repowered equipment.

Regarding the second risk, Mr. Hemstreet demonstrates in his rebuttal testimony that there is no risk regarding the value of the new components that are to be provided under the repowering contracts because the Company is using actual costs–which are largely subject to fixed price contracts–to measure the 80-percent value. Mr. Hemstreet also addresses how the Company has assessed the risk that the final costs are less than expected.

Q. Does any other DPU witness address the Company's ability to meet the 80/20 test?

A. Yes. DPU witness Mr. David Thomson also addresses this issue and concludes, in contrast to Mr. Peaco, that the "Company will generally be able to meet the provisions of the IRS 80/20 rule." (Thomson Direct, lines 88 - 89.)

CONSIDERATIONS RELATED TO FEDERAL CORPORATE INCOME TAX REFORM

Q. Mr. Peaco, along with OCS witnesses Mr. Mangelson, Mr. Hayet, and Ms. Ramas, and UAE witness Mr. Higgins, argue that the economic value of the wind repowering project may be adversely impacted if the federal corporate income tax rate decreases. How do you respond to this concern?

A. There is currently a great deal of discussion about the possibility of federal tax reform, but very little certainty over whether Congress will act. Various frameworks are circulating, including President Trump's brief outline for tax reform, the GOP Tax

Reform 2016 blueprint, and a tax reform framework developed by administration and Congressional leaders. To be clear, Congress is not currently considering specific legislative proposals because no bills have been introduced, only broad concepts, and it appears that Republicans in Congress are not united in their view of the essential components of tax reform.

In addition, there are deep divisions between Republicans and Democrats in Congress regarding the goals of tax reform. Republicans will likely need to use budget reconciliation to pass any tax reform bill in the Senate, which requires only a simple majority of votes when associated with temporary budget measures rather than the 60 votes required for permanent tax law changes. Normally, 60 Senators are required to end debate in the Senate. This generally means that 60 votes are required to pass legislation in the Senate versus a bare majority of 51 votes (50 in case of a tie with the Vice President casting the deciding vote). However, under the Senate Rules, the reconciliation process can be used to pass budgetary legislation, like tax reform, with a bare majority of the Senate. An important caveat is that the budget-reconciliation process cannot be used if the legislation creates an increase in the deficit after 10 years. Preliminary analysis of the various proposals indicates that the framework proposals are likely to increase the deficit unless high economic growth rates are achieved. This may make it impossible to use the reconciliation process to enact tax reform, creating further uncertainty as to the potential for tax reform to be enacted. In addition, controversy exists between and within the two political parties about how items such as the deduction for state and local taxes should be addressed.

Based on the deep political divisions between the two parties on the goals of tax reform and the large economic impact surrounding all the major areas of tax reform, the Company believes that at this time it is pure speculation to try to determine the ultimate outcome of tax reform in 2017. Therefore, for purposes of modeling a tax sensitivity for repowering, the Company assumed a congressional compromise on the corporate income tax rate, reducing the rate to 25 percent versus the current 35 percent corporate income tax rate.

Q. Messrs. Peaco and Hayet perform economic analysis of the repowering project assuming a 15 percent federal corporate income tax rate. (Peaco Direct, lines 761 - 771; Hayet Direct, lines 365 - 379.) Is a 15 percent tax rate a reasonable assumption?

A. No. Based on the current political dynamics, the Company does not believe that the federal corporate income tax rate will be reduced to 15 percent, which is more than a 50 percent reduction from the current tax rate.

Q. Under the most likely schedule for tax reform legislation, will the Company have time to assess tax changes before irrevocably committing to the wind repowering project?

A. Yes. The Company believes that the window for Congress to enact tax reform legislation is likely to close by early 2018 given the run-up to the mid-term Congressional elections. Thus, in early 2018, the Company will likely know the outcome of potential legislative changes that might impact corporate tax rates and impact the customer value of the repowering project. Because the Company does not expect to execute a turbine supply contract with Vestas until early 2018 nor issue a retrofit work order under the GE contract until after that time, the Company will not be committed to the repowering project before knowing the outcome of the ongoing discussions on tax reform.

As discussed further in Mr. Hemstreet's testimony, the Company negotiated terms in the GE master retrofit agreement that provide an off-ramp in the contract before issuance of a retrofit work order if tax law changes diminish the value of the projects. Thus, the Company does not expect to make irrevocable contractual commitments to the wind repowering project until the likely outcome of legislative tax reform proposals are known.

Q. Does the Company believe that tax reform will impact the phase-out of the PTCs?

A. No. Even if tax reform is passed, the Company does not believe it will impact the existing phase-out of the PTC previously enacted by the PATH Act.

Q. Has the Company accounted for the possibility of a lower 25 percent federal income tax rate in its updated economic assessment of the wind repowering project?

A. Yes. As discussed by Mr. Link in his rebuttal testimony, the Company has evaluated the wind repowering project under a scenario that reflects a potential adjustment to the corporate tax rates and found that the project still provides customer benefits.

Q. Does this conclude your rebuttal testimony?

A. Yes.