ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 320
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June 30, 2017

VIA ELECTRONIC FILING

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

In accordance with Utah Public Service Commission Rule 746-1-203, Rocky Mountain Power hereby submits for electronic filing its application requesting that the Commission (a) determine that the Company's decision to upgrade or "repower" most of its existing wind facilities is prudent, (b) approve the Company's continued recovery of the replaced wind plant equipment, and (c) approve the Company's proposed ratemaking treatment. As requested by the Commission, Rocky Mountain Power is also providing seven (7) printed copies of the filing via overnight delivery. Workpapers supporting this application will also be provided electronically. Rocky Mountain Power is currently preparing pro hac vice motions on behalf of its counsel at McDowell Rackner Gibson PC.

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

By E-mail (preferred):	datarequest@pacificorp.com Bob.lively@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Sincerely,

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Vice President, Regulation

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Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE VOLUNTARY REQUEST OF ROCKY MOUNTAIN POWER FOR APPROVAL OF RESOURCE DECISION TO REPOWER WIND FACILITIES	Docket No. 17-035-39 **Application for Approval of Resource Decision to Repower Wind Facilities**

I. INTRODUCTION

In accordance with Utah Code Ann. § 54-17-402, PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or "Company") submits this Application to the Public Service Commission of Utah ("Commission"). The Company respectfully requests approval of its decision to upgrade or "repower" existing wind resources, as prudent and in the public interest, contingent upon approval of (a) the Company continuing to recover the costs of the existing assets that will be repowered and (b) the Company's proposed ratemaking treatment. The Company proposes to upgrade or "repower" its wind resources because it provides net benefits to customers by increasing energy production, reducing operating costs, and requalifying the Company's existing wind resources for federal production tax credits ("PTCs"), which expire 10 years after a facility's original commercial operation date. To achieve the full PTC benefits, the Company must complete the wind repowering project by the end of 2020.

Wind repowering includes the installation of new rotors with longer blades and new nacelles with higher-capacity generators, which will increase energy output by an average of 19 percent without changing the footprint, towers, foundations or energy collector systems of the wind facilities. Using modern technology and improved control systems, the repowered wind facilities will produce more cost-effective energy, using zero-cost fuel over an extended useful life at reduced operating costs, saving customers millions of dollars. Because existing towers and foundations will remain in place and the footprint of the existing facilities are unchanged, the wind repowering project also results in minimal environmental impact and permitting requirements.

The Company estimates that the wind repowering project will cost approximately $1.13 billion. Because of the magnitude of this capital investment and the overall scope of the project, the Company requests that the Commission approve the wind repowering project before the Company completes equipment orders and begins construction. The Application gives the Commission and interested parties a meaningful opportunity to evaluate the wind repowering project to ensure that the project is reasonable, prudent, and in the public interest.

II. THE APPLICANT

1. PacifiCorp is a public utility providing retail electric service to customers in the six western states of Utah, Wyoming, Idaho, Oregon, Washington, and California, and wholesale electric service throughout the western United States. PacifiCorp provides electric service to retail customers in the state of Utah through its Rocky Mountain Power division, which serves approximately 840,000 customers and has approximately 2,000 employees in Utah.

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

By e-mail (preferred): datarequest@pacificorp.com

By regular mail:

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825 NE Multnomah, Suite 2000
Portland, Oregon 97232

With copies to:

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Informal inquiries related to this Application should be directed to Bob Lively, Utah Regulatory Affairs Manager, at (801) 220-4052.

III. SUPPORTING TESTIMONY

3. This Application is supported by the pre-filed written direct testimony and exhibits of the following Company witnesses:

- **Cindy A. Crane,** President and Chief Executive Officer of Rocky Mountain Power, testifies on the financial ability of the Company to make the wind repowering investment, explains the significant benefits to customers from repowering the Company's wind resources, and outlines the reasons why the wind repowering project is prudent and in the public interest. Ms. Crane also briefly describes the Company's proposals for ratemaking treatment and the continued recovery of the costs of the equipment replaced at the time of repowering.
- **Timothy J. Hemstreet**, Director of Renewable Energy Development, provides a detailed scope of the Company's wind repowering project, including technical

details, qualification for PTC benefits, increased energy production, reduced operating costs, and continued system reliability. Mr. Hemstreet also addresses the status and timing of wind-turbine-generator ("WTG") equipment purchases, construction requirements, anticipated construction timelines, and the disposition of removed equipment.

- **Rick T. Link**, Vice President of Resource and Commercial Strategy, provides the economic analysis that supports the prudence of the Company's wind repowering project and quantifies the significant customer benefits resulting from repowering. Mr. Link also explains the wind repowering project planning and analysis included in the Company's 2017 Integrated Resource Plan ("2017 IRP").
- **Jeffrey K. Larsen**, Vice President of Regulation, explains the Company's proposal for the ratemaking treatment of the costs and benefits of the wind repowering project in rates, the accounting treatment of the replaced wind plant equipment, and the inter-jurisdictional allocation of costs.

IV. THE WIND REPOWERING PROJECT

A. The Wind Repowering Project Increases Efficiency and Lowers Operating Costs.

4. Recent advancements in wind generation technology, including innovations in wind turbine design and control systems, allow modern wind turbines to generate greater energy from available wind resources. To take advantage of these recent technologies, the Company proposes to repower most of its Wyoming wind fleet (Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap); the Marengo I, Marengo II and Goodnoe Hills facilities in Washington; and the Leaning Juniper facility in Oregon. These facilities currently represent a total of 999.1 megawatts ("MW") of installed wind capacity, with 594 MW in Wyoming, 304.6 MW in Washington, and 100.5 MW in Oregon.

5. Wind repowering involves the installation of new rotors with longer blades and new nacelles with higher-capacity generators. Longer blades increase the wind-swept area of the wind

turbine and allow it to produce more energy at lower wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles will include sophisticated control systems and more robust mechanical and generator components necessary to handle the greater loads that come with longer blades. Together, the new rotors and nacelles are estimated to increase wind project generation from 11 to 35 percent, or an overall average of 19 percent (21 percent after new interconnection agreements are executed).

6. In addition, the innovative technologies provide for greater control of power quality and voltage, allowing the Company to more easily integrate the energy from the wind facilities into the transmission system and support the reliability of the grid. The new equipment also reduces future operating costs and extends the useful life of each wind plant by approximately 10 years. Over the current life of the repowered facilities, incremental annual energy production exceeds 550 gigawatt hours ("GWh"). Over the extended life, the incremental annual energy production exceeds 3,280 GWh. Importantly, because the wind repowering project involves efficiency improvements to existing facilities, these benefits can be achieved without the costs and complexity of permitting and constructing wholly new facilities.

B. Completing the Wind Repowering Project by the End of 2020 Maximizes PTC Benefits for Customers.

7. The cost-effectiveness of the wind repowering project is driven in part by the fact that repowering requalifies the Company's existing wind facilities for PTCs, which are set to expire 10 years from their original commercial operation date (expiration dates range from 2016 through 2020). For 2017, wind facilities qualifying for the PTC receive 2.4 cents per kilowatt-hour—or $24 per megawatt-hour, a value adjusted annually based upon an inflation index.

8. To requalify for PTCs, the repowered wind facility must meet the Internal Revenue Service's 80/20 test—meaning that the fair market value of the retained property (*i.e.*, tower and foundation in the Company's proposed project) is no more than 20 percent of the facility's total value after installation of the new property (*i.e.*, nacelle and rotor). The Company has designed its

wind repowering project to satisfy this test to ensure that the repowered wind facilities are PTC-eligible.

9. Further, to ensure the repowered facilities are eligible for 100 percent of available PTC benefits, in December 2016, the Company contracted with global wind industry leaders General Electric, Inc., and Vestas-American Wind Technology, Inc., to purchase new WTG equipment. These "safe-harbor equipment" purchases allow the repowered wind facilities to qualify for 100 percent of the value of available PTCs, assuming commercial operation by the end of 2020.

10. To achieve commercial operation by 2020, the Company requests that the Commission approve this Application by December 29, 2017, to allow the Company to complete most of the wind repowering work in 2019. The renewal of the PTC has dramatically increased the demand for materials, equipment, and labor for wind facilities. The Company must order equipment and execute construction contracts by early 2018 to ensure that all repowered facilities achieve commercial operation by the end of 2020. A delay in regulatory approval may compromise the Company's ability to meet the 2020 deadline and achieve the PTC benefits.

11. The Company's construction schedule will maximize the value of the existing PTCs by minimizing the period between the expiration of the original PTCs and the eligibility for the new PTCs. The original PTCs expire 10 years after each plant became commercially operational. Thus, the PTCs for most of the facilities will expire in 2018 and 2019. Achieving commercial operation in 2019 for most of the facilities will minimize the time during which any wind facilities are ineligible for PTCs.

C. The Proposed Facilities Provide Substantial Customer Benefits and Advance the Public Interest.

12. The Company's 2017 IRP, filed with the Commission on April 4, 2017, identified wind repowering as a least-cost, least-risk resource. The 2017 IRP is designed to ensure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner that is consistent with the public interest. To that end, the IRP's primary objective is to identify the best mix of resources to serve customers over the short- and long-term, based on an analysis of the costs and

risks associated with various resource portfolios. The IRP identifies the preferred portfolio as the least-cost, least-risk portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while ensuring compliance with state and federal regulatory obligations. The preferred portfolio in the 2017 IRP includes repowering all of the wind facilities included in the Application, except Goodnoe Hills, which was still being analyzed when the IRP was filed.

13. The Company conducted a comprehensive economic analysis of the wind repowering project in support of the Application. This analysis demonstrates that wind repowering will provide substantial customer benefits. The Company analyzed nine different scenarios, each with varying natural gas and carbon dioxide ("CO_2") price assumptions, and all nine scenarios show customer benefits, ranging from \$41 million when assuming low natural gas and zero CO_2 prices to \$589 million when assuming high natural gas and high CO_2 prices. With medium natural gas price and CO_2 price assumptions, wind repowering results in customer benefits of \$359 million.

14. The wind repowering project creates these benefits by:

- Increasing energy production from the wind facilities between 11 to 35 percent as a result of longer blades and increased generator capacity;
- Reducing ongoing operating costs associated with aging wind turbines;
- Extending the useful lives of the wind facilities by at least 10 years;
- Increasing the output of renewable energy from existing assets, while avoiding the environmental impacts and view-shed issues associated with new facilities;
- Reducing customer costs by requalifying the wind facilities for PTCs for an additional 10 years; and
- Improving the ability of the wind facilities to deliver cost-effective renewable energy into the transmission system through enhanced voltage support and power quality.

D. Proposed Ratemaking Treatment.

15. The Company seeks approval of a new deferral and cost recovery Resource Tracking Mechanism ("RTM"), under Utah Code Ann. § 54-4-1, 54-4-23, 54-17-402, and 54-17-403, to

address the proper ratemaking treatment to match the annual costs and benefits of the wind repowering project until the incremental costs and benefits are fully reflected in base rates, primarily including incremental capital and operating costs, net power costs savings if not captured in the Company's Energy Balancing Account ("EBA"), and PTC benefits. This mechanism will align the costs and benefits so that customers receive the full net benefits from the repowering project while shareholders receive appropriate cost recovery of the prudent investment. Once the full costs are reflected in base rates in a general rate case, the Company proposes that the RTM continue to track only year-to-year changes in PTCs to capture the full impact of the new PTCs. The Company proposes to record and defer, on a monthly basis, these incremental capital and operating costs, net power costs savings not captured in the EBA, and PTC benefits, beginning with the on-line date of the first repowered facility.

16. The Company intends to file new depreciation rates in 2019. At that time, the Company will reset the 30-year depreciable life of the repowered wind facilities, effectively extending the depreciable life of the facilities by 10 to 13 years.

V. LEGAL STANDARD

17. Utah Code Ann. § 54-17-402 authorizes the Commission to approve a utility's proposed "resource decisions" outside of a general rate case. Resource decisions are defined to include decisions relating to "an energy utility's acquisition, management, or operation of energy production, processing, transmission, or distribution facilities or processes." Utah Code Ann. § 54-17-401(2)(a)(i). When considering a request to approve a resource decision, the Commission must determine "whether the decision is in the public interest." Utah Code Ann. § 54-17-402(3)(b). The public interest determination must consider the following:

- Whether the decision will most likely result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to the retail customers of the utility;
- Long-term and short-term impacts;
- Risk;

- Reliability;
- Financial impacts on the utility; and
- Other factors determined by the Commission to be relevant.

18. The Company's decision to repower its wind fleet contingent on approval of continued cost recovery of the replaced equipment and the Company's proposed ratemaking treatment is a resource decision under Utah Code Ann. § 54-17-401(2)(a)(i) because it involves the operation of energy production facilities. The Company requests preapproval of this resource decision to allow for Commission and intervenor review of the wind repowering project before construction begins. The Company can then respond to potential issues and address concerns before embarking on a project of this scope. This Application and the supporting testimony and exhibits provide the Commission and parties with a well-developed record for review and preapproval of the wind repowering project.

19. The wind repowering project is in the public interest. The Company's 2017 IRP and the updated analysis included in Mr. Link's testimony demonstrate the wind repowering project results in the "delivery of utility services at the lowest reasonable cost." Utah Code Ann. § 54-17-402(3)(b)(i). The wind repowering project increases the energy generation of the Company's existing wind facilities, while saving customers money by reducing operating costs and requalifying the facilities for PTCs. The substantial customer benefits exist across all market price and Clean Power Plan scenarios modeled in the 2017 IRP—demonstrating that the wind repowering project is not only least cost, it is also least risk. Utah Code Ann. § 54-17-402(3)(b)(iii).

20. The wind repowering benefits also accrue immediately due to the facilities' requalification for PTC benefits, while the extended life due to the installation of new rotors and nacelles will provide long-term, cost-effective, emission-free generation to serve Utah customers. Utah Code Ann. § 54-17-402(3)(b)(ii).

21. The Company anticipates that the total cost of the wind repowering project will be $1.13 billion. The Company will fund the wind repowering project through its normal sources of capital, both internal and external, including net cash flow from operating activities, public and

private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. Although the wind repowering project is a significant investment, the financial impact of repowering will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates. Utah Code Ann. § 54-17-402(3)(b)(v). In addition, preapproval of the Company's resource decision provides important regulatory support for the Company's current credit rating while it makes the significant capital investments set forth in the 2017 IRP.

VI. PROPOSED PROCEDURAL SCHEDULE

22. To achieve commercial operation of the repowering project by 2020, the Company requests that the Commission adopt the following schedule, with a proposed decision by December 29, 2017:

June 30, 2017	Application Filed
July 7, 2017	Scheduling Conference
July 31, 2017	Technical Conference
September 13, 2017	Intervenor Testimony Due
October 11, 2017	RMP Rebuttal Testimony Due
October 25, 2017	Sur-Rebuttal Testimony Due
November 20, 2017	Hearings Begin
December 29, 2017	Target Order Issued

VII. REQUEST FOR RELIEF

23. WHEREFORE, the Company respectfully requests that the Commission:

1. Issue an order under Utah Code Ann. 54-17-402 approving the Company's energy resource decision for wind repowering as being prudent and in the public interest, contingent on (a) the continuing cost recovery of the Company's replaced assets, and (b) approval and implementation of the Company's proposed ratemaking treatment;

2. Issue a notice of scheduling conference to set a schedule:

   a. For interested parties to file comments or testimony;

   b. For any technical conferences deemed useful to the Commission or interested parties;

c. For a hearing on these requests; and

d. For other processes and procedures deemed reasonable or necessary by the Commission in determining whether to approve this request.

24. Rocky Mountain Power will authorize construction as soon as the Commission grants the approval and other regulatory and permitting requirements are met.

DATED this 30th day of June, 2017.

Respectfully submitted,

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Attorneys for Rocky Mountain Power

ATTACHMENT A

R746-440-1(1)(a)-(k) Information Location Matrix

Paragraph	Filing Requirement	Testimony and Exhibits
(a)	A description of the Resource decision	Hemstreet testimony
(b)	Information to demonstrate that the Energy utility has complied with the applicable requirements of the Act and Commission rules	1. *Prefiling Notice of Intent to File a Voluntary Request for Approval of Significant Energy Resource Decision*, filed June 23, 2017. 2. Hemstreet testimony 3. Link testimony 4. Larsen testimony
(c)	The purposes and reasons for the Resource decision	Hemstreet testimony
(d)	An analysis of the estimated or projected costs of the Resource decision, including the engineering studies, data, information and models used in the Energy utility's analysis	1. Hemstreet testimony 2. Link testimony
(e)	Descriptions and comparisons of other resources or alternatives evaluated or considered by the Energy utility, in lieu of the proposed Resource decision	Link testimony
(f)	Sufficient data, information, spreadsheets, and models to permit an analysis and verification of the conclusions reached and models used by the Energy utility	Link testimony
(g)	An analysis of the estimated effect of the Resource decision on the Energy utility's revenue requirement	1. Link testimony 2. Larsen testimony
(h)	Financial information demonstrating adequate financial capability to implement the Resource decision	Crane testimony
(i)	Major contracts, if any, proposed for execution or use in connection with the Resource decision	Hemstreet testimony
(j)	Information to show that the Energy utility has or will obtain any required authorization from the appropriate governmental bodies for the Resource decision	Hemstreet testimony
(k)	Other information as the Commission may require	No other information has currently been requested.

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

Direct Testimony of Cindy A. Crane

June 2017

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

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am the President and Chief Executive Officer of Rocky Mountain Power ("Company"), a division of PacifiCorp.

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990. Since then I have served as Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, Vice President of Strategy and Division Services, and Vice President of Interwest Mining Company and Fuel Resources. My responsibilities in these positions included the management and development of the Company's 10-year business plan, directing operations of the Energy West Mining and Bridger Coal companies, and coal supply acquisition and fuel management for the Company's coal-fired generating plants. In October 2014, I was appointed to my present position as President and Chief Executive Officer of Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before public service commissions in all states in which the Company serves customers, including before the Public Service Commission of Utah ("Commission").

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony explains the significant benefits to customers from repowering the Company's existing wind resources and outlines why wind repowering is a time-limited resource opportunity for customers that is both prudent and in the public interest. I describe the Company's proposal for the ratemaking treatment of the wind repowering project, and request continued cost recovery of equipment replaced by repowering. I also briefly describe the financial ability of the Company to make the wind repowering investment.

Q. Please summarize your testimony.

A. The Company plans to upgrade or "repower" 999.1 megawatts ("MW") of Company-owned, installed wind capacity (594 MW in Wyoming, 304.6 MW in Washington, and 100.5 MW in Oregon) with longer blades and new technology to generate more energy in a wider range of wind conditions. The upgrades are expected to increase output of the wind facilities by 19 percent on average, extend the operating life of the facilities, and allow the facilities to requalify for federal production tax credits ("PTCs") for an additional 10 years. To receive the full PTC benefits for customers, the repowered facilities must be commercially operational by the end of 2020.

Although wind repowering will cost an estimated $1.13 billion, the benefits generated by the repowering will produce net savings for customers over the life of the repowered facilities.

Because of the magnitude of this capital investment and the overall scope of the project, the Company requests that the Commission find that wind repowering is prudent now, before the Company commits to the costs of major equipment orders and equipment installation contracts, in accordance with Utah Code Ann. § 54-17-402. The Company also requests that the Commission approve its proposed ratemaking treatment, under Utah Code Ann. § 54-4-23, for the repowering investment, and its proposed continued recovery of the equipment replaced at the time of repowering. As described here and in the testimony of the Company's other witnesses, wind repowering provides substantial customer benefits and furthers the public interest. The Company's request for approval at this time gives the Commission a meaningful opportunity to evaluate the wind repowering project to ensure that the project is reasonable, prudent, and in the public interest.

Repowering is a time-limited resource opportunity for customers because of the challenges of meeting the 2020 PTC-qualification deadline. Therefore, the Company requests that the Commission issue its order approving the wind repowering project by December 29, 2017, to provide the Company sufficient time to execute the necessary contracts and complete the undertaking.

Q. What other witnesses will be testifying on behalf of the Company?

A. The Company's filing is supported by testimony from the following witnesses:

Mr. Timothy J. Hemstreet, Director of Renewable Energy Development, provides a detailed scope of the Company's wind repowering project, including technical details, qualification for PTC benefits, increased energy production, reduced operating costs, and continued system reliability. Mr. Hemstreet also addresses the status and timing of wind-turbine-generator ("WTG") equipment purchases, construction requirements, anticipated construction timelines, and the disposition of removed equipment.

Mr. Rick T. Link, Vice President of Resource and Commercial Strategy, testifies on the economic analysis that supports the prudence of the Company's wind repowering project and quantifies customer benefits resulting from repowering.

Mr. Link also explains the wind repowering planning and analysis included in the Company's 2017 Integrated Resource Plan ("2017 IRP").

Mr. Jeffrey K. Larsen, Vice President of Regulation, explains the Company's proposal for the ratemaking treatment of the costs and benefits of the wind repowering project in rates, the accounting treatment of the replaced wind plant equipment, and the inter-jurisdictional allocation of costs.

Q. Is the Company requesting approval of the wind repowering project in any other states?

A. Yes. The Company is requesting approval of wind repowering from the Wyoming Public Service Commission and the Idaho Public Utilities Commission. In Oregon and Washington, the Company has special rate-recovery mechanisms for investments in renewable resources that provide a path to recovery of the costs and benefits of wind repowering—the Renewable Adjustment Clause in Oregon and a generation deferral mechanism allowed by Washington law. In California, the Company is required to file a general rate case in 2019, which will include the costs and benefits of wind repowering.

OVERVIEW OF REPOWERING

Q. Please describe the Company's plans to repower its wind facilities.

A. Wind repowering takes advantage of technological advancements that allow greater generation from existing wind resources. Wind repowering involves installation of new rotors with longer blades and new nacelles with higher-capacity generators. These plant upgrades significantly increase energy output without changing the footprint, towers, foundations and energy collector systems of the wind facilities. Longer blades allow wind turbines to produce more energy over a wider range of wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles will include sophisticated control systems and more robust components necessary to handle the greater loads that come with longer blades.

Together, the new rotors and nacelles are estimated to increase generation from the repowered turbines by 13 to 35 percent, resulting in an overall average generation increase of 19 percent (or 21 percent after new interconnection agreements are executed). Mr. Hemstreet's testimony provides greater detail on the technical aspects of the wind repowering project.

Q. Which wind resources will be repowered?

A. The Company proposes to repower most of its Wyoming wind fleet (Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap); the Marengo I, Marengo II and Goodnoe Hills facilities in Washington; and the Leaning Juniper facility in Oregon. This represents a total of 999.1 MW of installed wind capacity, with 594 MW in Wyoming, 304.6 MW in Washington, and 100.5 MW in Oregon.

Q. What is the expected cost of wind repowering?

A. The Company estimates that wind repowering will cost approximately $1.13 billion.

Q. Why are you proposing to repower the Company's wind fleet now?

A. On December 18, 2015, Congress enacted changes to the federal Internal Revenue Code that extended the full value of the PTC for wind energy facilities that began construction in 2015 and 2016. The Internal Revenue Service ("IRS") has issued guidance that establishes a “safe harbor” for taxpayers to demonstrate the year a facility will be deemed to “begin construction,” thereby setting the value of the PTC.

Repowering the Company’s wind fleet now will allow the resources to requalify for PTCs, which will expire 10 years from the original commercial operation date of the resource (expiration dates range from 2016 through 2020). To maximize the PTC benefit, in December 2016, the Company contracted with General Electric, Inc., and Vestas-American Wind Technology, Inc., for the purchase of new WTG equipment. These safe-harbor equipment purchases allow the repowered facilities to qualify for 100 percent of available PTC benefits if they are commercially operational within four calendar years—or by the end of 2020. The Company’s purchases last year were important because wind facilities that begin construction after 2016 and come online after 2020 will receive a 20 percent decrease in the tax benefits that can be passed on to customers each year. Thus, a delay in acquiring the safe-harbor equipment would have made the economics of repowering less attractive and deprived customers of the substantial benefits that can be achieved if repowering is completed by the end of 2020.

To meet the 2020 deadline, the Company plans to order the necessary equipment and execute the necessary contracts in early 2018 and complete much of the construction in 2019. The renewal of the PTC has dramatically increased the demand for materials, equipment, and labor for wind facilities. By completing construction in 2019, the Company will mitigate the risk of construction delays, or delays associated with the procurement of equipment, and allow sufficient time to meet the 2020 deadline.

In addition, completing the majority of the construction in 2019 will maximize the value of the existing PTCs, while minimizing the period between the expiration of the prior PTCs and the eligibility for the new PTCs. By achieving commercial operation in 2019 for most of the facilities (Dunlap will be completed in 2020), the Company will also minimize the time during which the wind facilities are ineligible for PTCs.

Q. Is the Company requesting continued cost recovery of the equipment that will be replaced as part of the wind repowering project?

A. Yes. The Company is requesting to continue full cost recovery of the plant equipment that is replaced due to the wind repowering project. The existing net plant is currently in rates and has been assessed as part of the overall economic evaluation of project benefits to customers. The Company's decision to pursue the wind repowering project is dependent on the Company continuing to recover the investments in these Company-owned wind facilities that are currently included in customer base rates.

Q. Given that wind repowering is a time-limited resource opportunity, what is the Company seeking in this case?

A. The Company requests that the Commission issue an order by December 29, 2017, approving the resource decision to repower the wind facilities, as authorized by Utah Code Ann. § 54-17-402, approving the continued recovery of replaced plant equipment, and approving the Company's proposed ratemaking treatment. This will allow the Company to execute the necessary contracts and procure the equipment required to achieve commercial operation of all repowered units by December 31, 2020.

CUSTOMER BENEFITS

Q. What are the customer benefits resulting from wind repowering?

A. The customer benefits resulting from wind repowering derive in part from the fact that repowering allows the Company's existing wind resources to requalify for federal PTCs—which are then passed through to customers. As noted above, the Company expects repowering to cost approximately $1.13 billion. The customer benefits, however, are expected to exceed that cost—meaning that wind repowering will save customers money.

Wind repowering creates these benefits by:

- Increasing energy production from the wind facilities between 11 to 35 percent because of longer blades and higher capacity generators;
- Reducing ongoing operating costs associated with aging wind turbines;
- Extending the useful lives of the wind facilities by at least ten years;
- Reducing customer costs by requalifying the wind facilities for PTCs for an additional 10 years; and
- Improving the ability of the wind facilities to deliver cost-effective, renewable energy into the transmission system through enhanced voltage support and power quality.

The repowered facilities will deliver cost-effective energy to Utah customers, while saving customers money over the life of the investment.

Q. Did the Company analyze wind repowering in its most recent IRP?

A. Yes. The Company's 2017 IRP, which was filed with the Commission April 4, 2017, includes wind repowering as an integral component of the preferred portfolio—meaning that it was selected as a least-cost, least-risk resource option.

Q. Does the Company's economic analysis demonstrate that the wind repowering project will provide net benefits to customers?

A. Yes. The Company's economic analysis of the wind repowering project demonstrates that it will provide substantial customer benefits. As described in more detail in Mr. Link's testimony, the Company analyzed nine different scenarios, each with varying natural gas and carbon dioxide ("CO_2") price assumptions, and all nine scenarios show customer benefits, ranging from $41 million when assuming low natural gas and zero CO_2 prices to $589 million when assuming high natural gas and high CO_2 prices. With medium natural gas price and CO_2 price assumptions, wind repowering results in customer benefits of $359 million.

Q. After the Company filed its IRP in April, did Company representatives meet with Utah stakeholders to provide an overview of this filing?

A. Yes. From May 9 to 11, 2017, the Company met with various Utah stakeholders to review the details of its wind repowering proposal and discuss the scope and timing of this filing.

Q. How does the Company plan to reflect the net benefits of wind repowering in Utah rates?

A. As explained by Company witness Mr. Larsen, the Company proposes a new Resource Tracking Mechanism ("RTM") to address the proper ratemaking treatment to match the annual costs and benefits of wind repowering until the incremental costs and benefits are fully reflected in base rates, primarily including incremental capital and operating costs, net power costs savings not already captured in the Company's Energy Balancing Account ("EBA"), and PTC benefits. This mechanism will align the costs and benefits so that customers receive the full net benefits from the repowering project while shareholders receive appropriate cost recovery of the prudent investment. Once the full costs are reflected in base rates in a general rate case, the Company proposes that the mechanism continue to track only year-to-year changes in PTCs to capture the full impact of the new PTCs.

Q. If wind repowering provides such substantial benefits, why is the Company seeking approval now?

A. Because of the magnitude of the investment and the scope of the repowering project, the Company wants to provide the Commission and stakeholders an opportunity to review and provide meaningful input into the wind repowering decision before contracts are executed and construction begins.

In addition, it is important that parties understand the rate treatment of the project before the Company makes this significant investment to ensure that the costs and benefits will be properly matched and customers and shareholders will be fairly treated.

Q. How does the Company intend to finance wind repowering?

A. The Company intends to finance the proposed wind repowering through its normal sources of capital, both internal and external, including net cash flow from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions, and other sources. Although repowering is a significant investment on the part of the Company, the financial impact will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates.

Q. How will approval of the Company's application support the Company's current credit rating?

A. Ratings agencies consider the Company's regulatory treatment when establishing its credit rating, and particularly focus on the treatment of capital investments. Supportive treatment through approval of an investment of this magnitude provides assurance to ratings agencies and helps maintain the Company's credit rating. A solid credit rating directly benefits customers by ensuring access to capital markets, reducing immediate and future borrowing costs related to the financing needed to support regulatory operations. Strong ratings will often help the Company avoid costly collateral requirements that are typically imposed on lower-rated companies when securing power in the market. If the Company does not have consistent access to the capital markets at reasonable costs, its debt issuances and the resulting costs of constructing the new facilities become more expensive than they otherwise would be.

REQUIREMENTS FOR APPROVAL OF A RESOURCE DECISION

Q. What are the requirements for approval of a resource decision under Utah Code Ann. § 54-17-402?

A. It is my understanding that Utah Code Ann. § 54-17-402 authorizes the Commission to approve a utility's proposed "resource decision," including a decision like repowering that relates to the management or operation of an existing generating plant. I further understand that Utah Code Ann. § 54-17-402(3)(b) states that the Commission must determine whether the decision is in the public interest, taking into consideration the following factors:

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

Q. Based on these factors, is the repowering decision in the public interest?

A. As described above, and in more detail in the testimony of Mr. Link, repowering provides substantial customer benefits and is in the public interest. Repowering increases the energy generation of the Company's existing wind facilities, while saving customers money, and repowering provides these substantial customer benefits across all market price and Clean Power Plan scenarios modeled in the 2017 IRP—demonstrating that wind repowering is both least-cost and least-risk. The benefits of repowering accrue through the extended life of the existing wind resources, thus providing long-term, cost-effective, emission-free generation to serve Utah customers.

Moreover, as described above, the repowering project will not have an adverse financial impact on the Company and approval of the resource decision will provide further customer benefits by bolstering the Company's credit rating to better ensure continued access to low cost capital.

CONCLUSION

Q. What is your recommendation to the Commission?

A. I recommend that by December 29, 2017, the Commission issue an order finding that the Company's decision to repower its wind fleet is prudent and in the public interest, approving the Company's proposals for ratemaking, and for the continued recovery of the replaced equipment. Approval will provide certainty to the Company and enable it to move forward with confidence as it embarks on a project of this magnitude on behalf of its customers.

Q. Does this conclude your direct testimony?

A. Yes.

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

Direct Testimony of Timothy J. Hemstreet

June 2017

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

A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah Street, Suite 1500, Portland, Oregon 97232. My present position is Director of Renewable Energy Development. I am testifying on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I hold a Bachelor of Science degree in Civil Engineering from the University of Notre Dame in Indiana and a Master of Science degree in Civil Engineering from the University of Texas at Austin. I am also a Registered Professional Engineer in the state of Oregon. Before joining the Company in 2004, I held positions in engineering consulting and environmental compliance. Since joining the Company, I have held positions in environmental policy, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed the role of Director of Renewable Energy Development, in which I oversee the development of renewable energy resources.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. In support of the Company's application for approval of wind repowering and associated ratemaking treatment, my testimony provides technical information regarding the Company's proposal to upgrade, or "repower," most of its wind fleet. Specifically, my testimony addresses:

- The scope of the project;

- The benefits of repowering resulting from the qualification for federal production tax credits (“PTCs”);
- The increased energy benefits following repowering;
- The reduced ongoing operating costs following repowering;
- System transmission reliability related to the project;
- The extension of wind facility asset lives after repowering;
- Project contract status and construction schedule; and
- The disposition of removed equipment.

OVERVIEW OF WIND REPOWERING AND PROJECT SCOPE

Q. Please briefly describe what repowering a wind facility entails.

A. Repowering broadly describes the upgrade of an existing, operating wind facility with new wind-turbine-generator (“WTG”) equipment that can increase a facility’s generating capacity and the amount of electrical generation produced from the facility. Exhibit RMP___(TJH-1) is a depiction of a wind turbine and its various components. The Company proposes to repower its wind facilities by replacing the nacelle, hub and rotor of the WTG.

Q. Which facilities does the Company propose to repower?

A. The Company is planning to upgrade all of its wind facilities in Wyoming except the Foote Creek facility (Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap); the Leaning Juniper facility in Oregon; and the Marengo I, Marengo II, and Goodnoe Hills facilities in Washington.

Q. Please explain why repowering is feasible for these wind facilities.

A. The wind facilities the Company proposes to repower began commercial operations between 2006 and 2010. Because they were recently developed, they can be economically repowered, or upgraded, with new technology that will improve their efficiency and increase their generation output, while retaining the existing towers, foundations, and energy collection systems. The existing foundations and towers, although more than 10 years old in some instances, are adequately designed to accommodate larger, more modern WTG equipment and have a sufficient remaining useful life to economically justify the associated investment.

In contrast, at facility sites developed more than about 15 years ago, the WTG equipment typically has a low generating capacity (*i.e.*, sub-1,000 kilowatt) and the towers and foundations supporting the nacelle and rotor do not have the height or design strength to accommodate the installation of modern, larger nacelles and rotors capable of generating a much greater amount of electricity per WTG. With these older facilities, repowering usually involves the entire removal of the old wind turbine equipment and the redevelopment of the site with modern wind turbines that have much greater generating capacity. This can result in significantly fewer wind turbines needed to produce an equivalent generating capacity, while also increasing energy output.

The ability to repower facilities while reusing the existing infrastructure of the towers, foundations, and energy collection system is highly beneficial because the energy and PTC benefits can be realized with a lower capital investment, as compared to the more comprehensive site redevelopment required for older facilities.

Q. Did the Company's 2017 Integrated Resource Plan ("2017 IRP") evaluate repowering all of the resources covered by the application?

A. Yes, except for Goodnoe Hills. When the 2017 IRP was developed, the Company had not assessed repowering Goodnoe Hills. Since that time, however, the Company has evaluated the facility and believes Goodnoe Hills can be economically repowered similar to the facilities evaluated in the 2017 IRP.

Q. Why did the Company exclude Foote Creek in Wyoming from the proposed wind repowering project at this time?

A. As noted in the 2017 IRP action plan item 1a, the Company is still evaluating the potential of repowering Foote Creek. Repowering this older facility would involve more comprehensive site redevelopment, as described above, which is different in scope than the repowering projects proposed here. If the Company determines that repowering Foote Creek is economic for customers, it will pursue the appropriate regulatory process for doing so.

Q. How many megawatts ("MW") of installed wind capacity is the Company proposing to repower?

A. The Company is proposing to repower 12 of its 13 wind facilities, representing 999.1 MW of installed wind capacity. Broken down by state, this consists of eight facilities in Wyoming comprising 594 MW, one facility in Oregon of 100.5 MW, and three facilities in Washington comprising 304.6 MW. Detailed information about the wind facilities the Company proposes to repower is included in Exhibit RMP___(TJH-2).

BENEFITS OF REPOWERING INCLUDING REQUALIFICATION FOR PRODUCTION TAX CREDITS

Q. What benefits will customers realize from wind repowering?

A. Repowering the proposed wind facilities will requalify them for PTCs, and the benefits will be fully passed on to the Company's customers with the ratemaking treatment discussed by Company witness Mr. Jeffrey K. Larsen. Additionally, repowering will increase the amount of zero-fuel-cost energy produced from the repowered turbines which will range from 11 to 35 percent, depending on the facility.[1] It will reduce ongoing operating costs as a result of replacing older WTG equipment subject to more failure and maintenance issues than newer equipment. Finally, repowering the wind facilities with new WTG equipment will extend the useful lives of the facilities by at least 10 years, creating substantial energy benefits for customers in the future when these wind facilities would otherwise have been retired from service.

Q. How are the repowered wind facilities able to requalify for PTCs?

A. On December 18, 2015, Congress enacted changes to the federal Internal Revenue Code that extended the full value of the PTC for wind energy facilities that began construction in 2015 and 2016. The legislation also provided for a phase-out of the PTC over three years, reducing the PTC value by 20 percent for wind facilities beginning construction in 2017, 40 percent for wind facilities beginning construction in 2018, and 60 percent for wind facilities beginning construction in 2019. The Internal Revenue Service ("IRS") has issued guidance that establishes a "safe harbor" for taxpayers to demonstrate the year a facility will be deemed to "begin construction," thereby setting the value of the PTC. If at least five percent of the total project costs are incurred in 2016, then the facility qualifies under the IRS safe harbor for the full value of the PTC, provided the taxpayer can demonstrate "continuous efforts" to complete construction.

[1] This range reflects increases under existing transmission interconnection agreements. The range is 15 percent to 38 percent if transmission interconnection agreements are modified to reflect the additional capacity available from the repowered turbines.

The IRS has issued additional guidance that establishes a safe harbor for satisfying this continuous-efforts standard. Under the continuous-efforts safe harbor, the wind facilities must be in service by the end of the fourth calendar year following the calendar year in which construction began. Thus, wind facilities that began construction in 2016 must be in service no later than December 31, 2020, to satisfy the continuous-efforts safe-harbor provisions. If not installed by December 31, 2020, the projects must satisfy IRS requirements that continuous-efforts were expended to repower the facilities, which is a difficult standard to meet.

Q. Does the Company's repowering project qualify for the full value of the PTC under these rules?

A. Yes. Consistent with IRS guidance, a facility owner can demonstrate that construction of a facility has begun in the year in which at least five percent of the applicable project costs are incurred. If wind turbine equipment is purchased and delivered in 2016, and the equipment comprises at least five percent of the applicable project costs, a PTC safe harbor is created for the wind facilities subsequently constructed. To meet this requirement, the Company executed safe-harbor equipment purchases with General Electric International, Inc. ("GE") and Vestas American Wind Technology, Inc. in December 2016, and took delivery of equipment with a value sufficient to give the Company the ability to repower its entire wind fleet and qualify the repowered wind facilities for 100 percent of the PTC value.

Q. What is the value of the PTC for wind facilities?

A. For 2017, wind facilities that are qualified for the PTC receive 2.4 cents per kilowatt-hour, or $24 per megawatt-hour. This PTC value is adjusted annually based upon an inflation index, and the PTC is available for energy produced during the 10-year period after the wind facility begins commercial operation.

Q. What other requirements must repowered projects satisfy to qualify for the PTC?

A. On May 5, 2016, the IRS issued Notice 2016-31[2] ("Notice"), which provides guidance on various aspects of qualifying for the PTC and whether new tax credits can be claimed when wind turbines are repowered or retrofitted. The Notice generally provides that the repowering costs must equal at least four times the fair market value of the equipment that the owner retains from the original facility for the repowered turbines to qualify for new PTCs. Thus, 80 percent of the fair market value of the repowered WTG must result from repowering project costs while the value of the retained components cannot exceed 20 percent of the fair market value of the new facility. This "80/20" test is applied on a turbine-by-turbine basis. Each wind turbine—composed of a foundation, tower, and machine head (including nacelle, hub and rotor)—is considered a separate facility.

Q. Do all of the wind turbines the Company is proposing to repower meet this 80/20 test?

A. Yes. The repowering project has been scoped to ensure that the 80/20 test, which is applied at the time the turbine is repowered, will be met for each turbine repowered. Not all turbines at all wind facilities, however, will be repowered because the retained value of the towers and foundations at certain wind turbines does not allow them to meet the 80/20 test before the end of 2020, when the repowered wind facilities must be completed to obtain the full PTC value.

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[2] The IRS Notice 2016-31 is available at: https://www.irs.gov/irb/2016-23_IRB/ar07.html.

Q. Which wind facilities will not have all wind turbines repowered?

A. Repowering at Glenrock I, Rolling Hills and Glenrock III, located near Glenrock, Wyoming, will not include all wind turbines. At this location, 32 of the 158 wind turbines will not be repowered because the facilities were developed at the Company's reclaimed Glenrock coal mine. These 32 wind turbines were constructed atop mine tailings and required special pile foundations. These special foundations were more expensive to construct than the standard foundations found elsewhere on those facility sites and at other Company wind facility locations. Because the original construction cost of these foundations was higher than for standard foundations, the retained value of these foundations, which is based on net book value, is also higher than other foundations. For these 32 wind turbine locations, the higher retained value of the foundations means that repowering, while technically feasible, would not qualify those turbines for PTCs, which is necessary for the repowering to be economic. The Company plans to repower all of the turbines at the other wind facilities discussed above.

Q. How else has the Company scoped the repowering project to maximize the benefits of available PTCs?

A. As shown in Exhibit RMP___(TJH-2), the majority of the wind facilities the Company proposes to repower, with the exception of Leaning Juniper, are still within 10 years of their original commercial online date. Thus, the PTCs from original construction are still accruing to the benefit of the Company's customers. The existing PTCs for these wind facilities will expire 10 years after the facilities' commercial online date. Between August 2017 and October 2020, the PTCs associated with approximately 2.64 terawatthours ("TWh") of electricity generated at the Company's wind facilities will expire. On an annual basis, in 2017 dollars, the expiration of these PTCs represents the loss of approximately $100 million per year in customer PTC benefits, as shown in Exhibit RMP___(TJH-2).

To maximize the benefits of the existing PTCs available from the wind facilities, the Company will generally delay repowering until the original PTCs have expired. The exception to this is Dunlap, where the PTCs expire in October 2020. To repower Dunlap by the end of 2020, as required to re-qualify for PTCs, repowering must begin before October 2020 so construction can be completed before the winter season. This results in a slight truncation of the existing, original 10-year PTC period for that facility. As with all of the wind facilities, however, once Dunlap is repowered, it will then re-start a 10-year period where its generation is eligible for the full value of PTCs.

INCREASED ENERGY BENEFITS FOLLOWING REPOWERING

Q. Once repowered, how do the energy benefits of the wind facilities increase?

A. Repowering will involve the replacement of the existing machine heads including the nacelle, hub and rotor. The new nacelles have generators that, in most instances, have a greater nameplate generating capacity than the equipment that is removed. For example, the nameplate of each turbine at the Wyoming facilities will increase from 1.5 MW to 1.6 MW, while at the Marengo facility, the generator nameplate rating will increase from 1.8 MW to 2.0 MW. Details regarding the proposed wind turbine upgrades, capital project costs, in-service dates, and resulting energy benefits are shown in Confidential Exhibit RMP___(TJH-3).

In addition to the larger generators in the repowered turbines, the Company will also install larger blades. With the larger blades, the rotor-swept area of the wind turbines will increase between 28 to 56 percent, depending on the type of turbine. A larger rotor-swept area allows more of the wind energy flowing past the wind turbine to be captured and converted by the wind turbine into electricity. Because the size of the rotors will increase, the repowered turbines will also include more robust hubs, main shafts, bearings and couplings, and gearboxes suitable to handle the greater torque exerted by the larger rotors.

Q. Will the larger blades installed with repowering increase the potential for avian impacts at the Wyoming wind facilities?

A. Although the larger blades will increase the overall risk zone (rotor-swept area) of the repowered wind turbines, this does not necessarily correlate with an increased risk of avian impacts at existing turbine sites. The Company will continue to implement its current informed-curtailment protocols after repowering to minimize avian impacts. Informed curtailment involves the shutdown of wind turbines when species of interest are in the vicinity. The Company's informed-curtailment protocols avoid avian impacts regardless of the swept area of the rotor. The Company performs monthly monitoring at all Wyoming wind facilities and reports all findings to both the Wyoming Game and Fish Department and the U.S. Fish and Wildlife Service. The Company will continue this monthly monitoring to determine if the new turbine blades cause additional impacts to avian species and will engage with the appropriate agency to discuss and, if prudent and practicable, implement additional avoidance, minimization, or mitigation measures.

Q. How did the Company determine the amount of additional generation that will be produced from the repowered wind turbines?

A. The Company retained the engineering consulting firm of Black & Veatch, Inc. ("Black & Veatch") to evaluate increased energy production expected at each of the wind facilities from repowering. To complete this assessment, Black & Veatch used site wind data, wind turbine location data, operational performance data, and other available site-specific information for each facility to model this increased generation. The wind model also evaluated generation losses resulting from the wake losses at each turbine location. Wake losses are the reduction in generation at turbines downwind of other turbines due to reduced wind speed and increased turbulence in the airflow—or wake—behind a turbine.

Q. What are the major power production advantages of the new equipment?

A. The larger rotor size and improvements in blade design of the new equipment generate more power at all ranges of wind speeds. Additionally, some of the new turbines begin producing power at a lower wind speed than the existing equipment; thus, the turbines can produce energy during lower wind conditions in which the current equipment may sit idle. Because the new turbines, at most facilities, will have an increased generator capacity, the turbines will also produce more energy when wind speeds are high and the turbines are at their maximum output. These power production advantages are illustrated in Exhibit RMP___(TJH-4). This exhibit compares the power curves of an existing wind turbine to those of a repowered wind turbine.

Q. Why wasn't this larger equipment installed when the wind facilities were initially constructed?

A. Wind turbine technology has continued to advance since the facilities were first constructed between 2006 and 2010. The use of new composite materials has allowed blade lengths to increase without adding weight, allowing for the extraction of more energy from the available wind resources at the facility sites. In addition, more sophisticated sensor and control systems in the wind turbines, combined with improved blade pitch control systems, increase the ability of the wind turbine control systems to implement load mitigation strategies on the wind turbines to reduce the loading on the power train, towers and foundations. For new wind facilities, these technology improvements mean that longer blades and additional generating capacity is possible without a commensurate increase in cost to strengthen the turbine structural components (including the tower and foundation). For new wind facilities, this is one of the drivers towards reduced energy costs. For existing wind facilities, these new load mitigation technologies mean that the existing towers and foundations are suitable for the installation of larger equipment through repowering.

Q. How much additional energy will the repowered wind facilities produce?

A. As shown in Confidential Exhibit RMP___(TJH-3), across the wind fleet, the proposed repowered wind facilities are estimated to increase generation by 550,601 megawatt-hours ("MWh") per year if the facilities are operated within the limits of their existing large generator interconnection agreements—an increase of 19 percent. If the facilities are operated at their full generating capability following a modification to their interconnection agreements, the additional generation increases to 597,671 MWh per year, or an increase of 21 percent.

Q. Is the Company planning to use the additional generating capacity provided by the repowered wind turbines?

A. Yes. The Company has submitted generation interconnection applications to request increased output from the repowered wind facilities and transmission service requests to transmit power so that the full generation capability of the repowered facilities can be delivered to customers.

Q. Is the repowering project economic even without the ability of the wind facilities to generate at their full repowered nameplate capacity?

A. Yes, as Company witness Mr. Rick T. Link demonstrates in his testimony, the repowering projects are economic even if the facilities are operated within their existing transmission capacity limits. An adjustment to the large-generator interconnection agreements allows the facilities to be operated at full nameplate capability following repowering and simply improves the economics of the repowering project.

Q. With the rapid technological advances in the wind industry, will the Company be able to leverage any advancements for the repowering projects before the new equipment is installed?

A. Yes. Turbine manufacturers continue to develop new technologies and offerings to improve efficiency and reliability and reduce the overall cost of wind energy—both for new and repowered facilities. To the extent the Company's repowering projects can leverage these advancements, the Company will evaluate them and negotiate with the turbine suppliers to incorporate new product offerings to further enhance the benefits of the repowering the facilities for customers. For example, GE is developing a 91-meter rotor for repowering projects like the Company's that is based upon the proven designs of its existing rotor offerings. This new rotor will be compatible with the safe-harbor equipment the Company purchased in December 2016, and with the nacelles the Company is purchasing as follow-on equipment consistent with the contract with GE. This new rotor, if it can be applied to the Company's repowering project, would further increase the amount of energy produced as a result of repowering, resulting in additional customer benefits.

REDUCED ONGOING OPERATIONAL COSTS FOLLOWING REPOWERING

Q. Aside from increased generation and the associated PTC benefits, what other benefits will be realized with the repowering project?

A. The repowering project will lower the ongoing costs of operating the existing wind facilities. The Company's turbine-supply contracts for repowering, consistent with wind industry standards for new equipment, will include a two-year warranty on the new equipment. This will reduce capital costs associated with replacing or refurbishing the equipment currently in service. Additionally, the new turbine equipment associated with repowering, will obviate, to a large extent, capital costs associated with major turbine component replacements and refurbishments (generators, gearboxes, blades, and small components). After the two-year warranty period for the new equipment expires, these costs are expected to be lower than the costs for the current equipment that has now been in service for up to 11 years. Further, capital costs will be reduced before repowering as the investment horizon for the existing wind turbines closes and various capital replacements no longer make economic sense given the short remaining installed life of the turbines to be repowered.

Q. Will the Company's reduced capital investments during the transition to repowering cause a reduction in the generation from the facilities?

A. Yes, before repowering is complete, some of the existing turbines may experience component failures that render them unable to provide economic service. It will be more economic for customers to idle these turbines than repair them given the short period before repowering. As a result, the Company estimates that generation from the wind facilities targeted for repowering will be reduced before repowering. These pre-repowering generation impacts are factored into the economic analysis.

Q. Will the new equipment address any other operational cost issues?

A. Yes. In addition to the reduced capital run rate of the new equipment in its early years after installation, repowering will avoid costs from replacing certain major turbine components that are experiencing high failure rates. One category of avoided costs relates to failures of certain models of gearboxes found in the Wyoming wind fleet and Leaning Juniper and Marengo. These gearboxes, which are original equipment from the manufacturer, are experiencing high failure rates compared to other models of gearboxes installed in WTGs at these facilities and elsewhere within the wind fleet. Consequently, the Company has experienced increased capital costs in recent years to address the gearbox failures, and these models are no longer being re-installed as long-term replacement equipment after failure, given their poor historical performance.

Q. Why are these gearbox failures significant?

A. These gearbox failures generally cannot be repaired "up-tower." The repair cannot be completed within the nacelle without removing the damaged equipment by crane. These failures cost approximately $400,000 per occurrence, including equipment and labor costs to purchase and install a replacement gearbox and the costs of mobilizing a large crane to the site to remove and replace the equipment. These costs also do not account for the lost generation from the time the turbine is down until the repair is completed.

Q. How many gearbox failures of this type are expected if there is no repowering?

A. There are 230 of these gearbox models remaining in the wind fleet, and the Company anticipates that all of these remaining gearboxes will fail within the next 15 years.

Q. Will repowering completely address these gearboxes with shorter-than-anticipated service lives?

A. No. Ten of the 32 wind turbines that will not be repowered at Glenrock I, Glenrock III, and Rolling Hills have these gearbox models that will need to be replaced, which is factored into the economic analysis. Following repowering, these gearboxes—as well as potential failures of other gearbox models at the non-repowered units—can be replaced with those removed from the existing turbines as part of the repowering effort, reducing the repair costs of the remaining gearboxes. The cost savings of doing so, however, have not been factored into the Company's economic analysis because the Company is still evaluating how best to realize value for customers from the removed equipment.

Q. Are other significant capital costs avoided with repowering?

A. Aside from the gearbox issues, repowering will also avoid ongoing capital expenditures related to blade costs at Goodnoe Hills. Blade expenditures at this facility represent approximately 60 percent of the budgeted capital costs associated with blade failures and refurbishments across the Company's wind fleet, even though Goodnoe Hills accounts for only seven percent of the turbines. Repowering is expected to bring blade costs for that facility in line with the Company's expenditures at its other facilities, resulting in reduced capital costs to keep the wind fleet meeting its operational performance targets.

Given these ongoing gearbox and blade failure costs, repowering is particularly attractive because repowering avoids significant forecast capital expenditures to maintain turbine production. This addresses the predicted turbine failure, replaces the turbine equipment with new equipment that extends the asset life, and provides the benefit of increased generation from the turbine, while requalifying the wind turbine for PTCs for another 10-year period.

Q. Will the new repowering equipment have similar failure issues as the old gearboxes?

A. No. The gearbox models in the fleet that are experiencing high failure rates will not be included in the equipment installed for repowering because the gearbox specifications for the new equipment differ from the existing equipment. Thus, the Company does not expect to see these same gearbox models and their attendant reliability concerns. Further, the equipment that will be installed has evolved from the product lines of the existing turbines, rather than arising from new product offerings. Thus, the turbine suppliers have presumably learned from past experience with these turbine models and made adjustments in their designs, specifications, and choice of subcomponent suppliers to enhance turbine reliability. Because of the warranty service requirements in the turbine-supply contracts and because the turbine suppliers are often under long-term service agreements for the turbines they supply, the turbine suppliers have an incentive to improve the reliability of their turbines.

MAINTAINING TRANSMISSION SYSTEM RELIABILITY

Q. With the high concentration of wind in eastern Wyoming, and the increased wind turbine capacity from the repowering project, what measures are being taken by the Company to assure continued transmission system reliability?

A. In addition to adding new transmission infrastructure necessary to support the new wind resources that are the subject of the concurrently filed application for approval of the resource decision for transmission and new wind, the Company has identified the need to add two features to the wind turbine capabilities of the repowered facilities that will improve the reliability of the transmission system for eastern Wyoming. These reliability features will provide added support for system voltages during a wide range of operating conditions and increased system inertia to provide needed transmission system support during under-frequency system events.[3] These two features are summarized below and will be installed on the repowered units of the GE wind fleet in Wyoming:

- The WindFREE™ Reactive Power feature has been developed by GE for wind turbines to provide smooth fast voltage regulation by delivering controlled reactive power through all operating conditions. By supervising individual wind turbines, the WindCONTROL™ system ensures that the reactive power performance of a wind power plant can meet—and often exceed—the

[3] Under-frequency events occur when imbalances in system generation resources and load cause transmission system frequency to drop below 60 hertz, which can result in load shedding to restore system frequency.

performance of a conventional (non-wind) power plant. Even when wind turbines are not generating active power, GE's wind turbine generators equipped with the WindFREE™ Reactive Power control feature can provide reactive power. The provision of continued voltage support and regulation provides grid benefits not possible with conventional generation, while mitigating adverse voltage impacts of wind turbines being off-line due to wind conditions. This feature can eliminate the need for grid reinforcements specifically designed for no-wind conditions, and may allow for more economic commitment of other generating resources that will enhance grid security by reducing the risk of voltage collapse.

- The WindINERTIA™ control has been developed by GE to provide an inertial response capability for wind turbines that is similar to that of conventional synchronous generators during under-frequency grid events. By utilizing the mechanical inertia of the rotor, GE has designed the WindINERTIA™ power pulse characteristics to provide a five percent to 10 percent increase in turbine power over operational wind speeds. The duration of the power pulse is up to several seconds and benefits the grid by allowing other non-wind power generation assets time to respond by increasing power production.

Q. Are these features part of the current Wyoming GE wind fleet?

A. No, but with the additional capacity from repowering, and the increased amount of wind generation anticipated as part of the Company's current CPCN application, the Company believes these features will provide important system support capabilities after the facilities are repowered.

Q. How will these features benefit customers?

A. These features will improve transmission system reliability and will allow the Company greater flexibility in managing the transmission system in Wyoming. These features should defer the need to separately provide for transmission system voltage support through the construction of synchronous condensers or static VAr (volt-amp reactive) compensators.

Q. Have these reliability and deferred transmission system support costs been factored into the economic analysis of the repowering project?

A. No, these customer benefits are not currently included in the economic analysis because transmission studies are needed to quantify these benefits as compared to other alternatives. The Company is currently undertaking these studies.

EXTENSION OF WIND FACILITY ASSET LIFE AFTER REPOWERING

Q. What is the current asset life of the wind facilities that will be repowered?

A. All of the existing wind facilities are currently being depreciated assuming a 30-year asset life. The facilities the Company plans to repower are currently scheduled to be retired between 2036 and 2040.

Q. Will repowering the wind facilities extend their useful operating lives beyond the currently planned retirement dates?

A. Yes, repowering the wind facilities will extend their life an additional 30 years from the repowering date, extending their useful lives by at least 10 years.

Q. How will repowering extend the useful life for an additional 30 years?

A. The repowering projects are being designed by the turbine equipment suppliers to meet the same design requirements that apply to complete wind turbine generators used in new wind facility construction. The wind turbine equipment suppliers are contractually required, as would be the case with a new wind facility, to have their wind turbine designs for the repowering projects certified by an independent third party to ensure that they meet or exceed applicable International Electrotechnical Commission design standards used in the wind turbine industry. These design standards are intended to ensure that the equipment is appropriate for the site conditions and will perform satisfactorily over the standard design life.

Q. What factors will be independently reviewed to assess and certify the design?

A. The third-party design assessment evaluates the site-specific load assumptions based upon the climactic conditions at each facility and will assess the control and protection systems for the wind turbine and their ability to meet the site design conditions. It will also assess the electric components, the rotor blades, hub, machine components (*i.e.*, drivetrain, main bearing and gearbox), and the suitability of the existing tower upon which the new wind turbine equipment will be installed.

Q. Does the design certification also evaluate the ability of the existing foundations to handle the loads associated with the repowered turbines?

A. No. The design certification will assess the design loads and the design assumptions regarding the ability of the new turbines and the existing towers to handle those loads. But as with new wind facility development, the facility owner must provide a foundation suitable to handle the loads imparted by the tower on the foundation.

Q. Has the Company reviewed the foundations to ensure they are capable of handling the new turbines?

A. Yes. The Company retained Black & Veatch to evaluate the ability of the existing foundations to handle the loads of the repowered turbines. For the Wyoming facilities and Marengo I and Marengo II, which have been fully designed, Black & Veatch's evaluation indicates that the existing foundations are suitable for the repowered turbines. For Leaning Juniper and Goodnoe Hills, foundation load evaluations have not yet been completed because those facilities are still under design review, which is expected to be completed by this fall. The suitability of the foundations will be confirmed when the design process is completed for those facilities and before executing contracts. Because of the load-mitigation controls now available with newer equipment, the future foundation loads at some of the facilities, even with the larger equipment, are less than the original design loads the foundations were engineered to withstand.

Q. Has the Company evaluated the foundations to determine if they are suitable for an additional 30-year service life following repowering?

A. Yes, for the foundations in which fatigue loading is a controlling design variable, and for which foundation load specifications are now available, the Company's consultant assessed the ability of the foundations to handle the estimated fatigue loading anticipated from an additional 30-year life following repowering and determined the foundations are able to accommodate the additional loading.

PROJECT CONTRACT STATUS AND CONSTRUCTION SCHEDULE

Q. What is the status of contracting related to the proposed repowering projects?

A. For the facilities that will be repowered with GE equipment, the Company is negotiating a turn-key master retrofit contract with GE to perform the repowering at a fixed price per turbine. This fixed-price contract will provide the Company the ability to execute retrofit work orders for the facilities to be repowered and will significantly mitigate cost uncertainty related to the facilities. For the facilities that will be repowered with Vestas equipment, the Company executed a master turbine-supply agreement on December 28, 2016, that facilitates future equipment supply in support of repowering, and will negotiate an installation contract with Vestas or with other qualified wind energy contractors.

Q. When must the Company execute contracts with the equipment suppliers to proceed with the repowering projects?

A. Under the terms of the master retrofit contract being negotiated with GE, for repowering projects to be completed before March 31, 2020, the Company must notify GE of its intent to execute a retrofit work order eight months before the date requested by the Company for commissioning of the first retrofitted unit for any facility. For repowering projects to be completed on or after March 31, 2020, the Company must notify GE of its intent to execute a retrofit work order 12 months before the date requested by the Company for completion of commissioning of the first retrofitted unit for that project. Similarly, the Company will need to execute a contract with Vestas 12 months before equipment deliveries begin for a particular repowering project. The Company's construction schedule has been developed to optimize the PTC benefits of the facilities and ensure that the facilities can be constructed during the low-wind season—between March and November. To meet the equipment supply lead times requires contract execution beginning in early April 2018. Allowing time to finalize and execute the repowering contracts, the Company must be in a position by March

2018 to proceed with these facilities. A detailed project schedule for the repowering projects is attached as Exhibit RMP___(TJH-5).

Q. Why is there such a long lead time between the execution of retrofit contracts and the time that turbines can actually be repowered or delivered to the site to support the repowering projects?

A. Like all equipment suppliers in the wind industry, both GE and Vestas are currently responding to unprecedented demand to supply equipment for wind facilities that are slated to be installed before December 31, 2020, to qualify the facilities for the full value of the PTC. Because this equipment is manufactured to order, long lead times are required to ensure manufacturing capacity is available and to meet specific project delivery requirements. In some cases, additional manufacturing capacity may need to be sourced or constructed to meet the equipment supply demands.

Q. Aside from manufacturing lead times, are there other drivers for the lead times associated with constructing these facilities?

A. Yes, in addition to the manufacturing constraints, lead times are necessary to ensure that construction contractors and work crews and cranes are available to install the repowering equipment. Because of the large-scale efforts involved in repowering the facilities, these resources must be secured well in advance of project construction to ensure project schedules are met. Also, both skilled labor resources and construction cranes are likely to be in short supply given the amount of activity involved in new wind facility construction and wind repowering projects across the country that must achieve commercial operation by December 31, 2020, to meet the safe-harbor rules summarized above in my testimony to qualify for the full value of the PTC. Thus, securing these necessary resources well before beginning these time-sensitive projects mitigates both cost and schedule risk for these beneficial projects.

Q. How has the Company designed the repowering projects to work within these constraints?

A. As discussed above, the 2019 construction schedule for most of the facilities, other than Dunlap, optimizes the existing PTC benefits of the facilities and also allows for their construction, generally, more than a year in advance of the December 31, 2020 deadline to achieve commercial operation.

Q. What permitting requirements apply to repowering projects and what steps has the Company taken to acquire any needed regulatory approvals for the repowering projects?

A. Because repowering does not increase the footprints of the existing wind facilities, and since the facilities are operating under current local, state and federal permits and authorizations, the permitting requirements for repowering are minimal. Because the facility footprints are not altered and since repowering is unlikely to disturb additional acreage not already covered by existing permits, additional standard construction permits, such as storm-water permits and fugitive dust permits, are likely not required. Throughout the repowering process the Company will ensure that the requirements of the existing permits and authorizations are met, and will provide needed information to permitting authorities to amend or modify the existing permits for the facilities to reflect the change in turbine equipment, if needed. This involves assessing whether amendments to the existing Wyoming Industrial Siting Division ("ISD") permits are required to reflect the new wind turbine equipment installed in Wyoming, as well as similar processes to amend existing county authorizations in other states, as well as modifications to Federal Aviation Administration authorizations to reflect the increased height of the turbine blades.

The Company has engaged with the Wyoming ISD to determine requirements for performing the repowering activities and based on those discussions, no additional permitting or permit amendments are anticipated, as the repowering efforts can be performed as operations and maintenance activities under the existing permits. Additionally, the Company has spoken with county authorities to determine local permitting requirements. Based on those discussions, the Company has identified the need for new building permits and/or amendments to existing county authorizations in several counties. The Company will obtain these permits/amendments before beginning the repowering project. The Company will continue to work with the appropriate regulatory and permitting authorities to provide information necessary to obtain any needed permits or to process any amendments or modifications to the existing facility permits.

DISPOSITION OF REMOVED EQUIPMENT

Q. What is the Company planning to do with the existing equipment that will be removed?

A. The Company has not yet determined how it will dispose of this equipment, but will explore various options to realize the greatest customer benefit from the equipment. Because the Company will be replacing the entire machine head (nacelle, hub, and rotor) of the repowered turbines, the removed equipment has the potential to be reused and redeployed to another site location. This may make the equipment valuable for redeployment elsewhere in the country, or perhaps elsewhere in North America.

The Company understands that a significant number of turbines of all makes and models will be repowered before 2020. This creates potential value for the removed equipment as spare parts for similar type turbines that will remain in service. This also makes it difficult, however, to use current market pricing for used turbines as a proxy for the potential salvage value of the equipment given the large number of repowered turbines and associated spare parts that will become available in the next several years. Because not all the Company's GE turbines will be repowered, some of the equipment can potentially be used as spare parts to service the non-repowered turbines.

Q. Given the uncertainty of the market for the removed equipment either for redeployment or as spare parts, what was assumed in the economic analysis for the salvage value of the equipment?

A. The Company did not assume any salvage value for the removed equipment in its economic analysis, which is a conservative assumption given the potential for the equipment to be reused, repurposed as spare parts, or merely salvaged for scrap metal value. To the extent the Company determines any salvage value by reusing the equipment, or by selling or auctioning it to third parties, the Company will pass through any and all additional financial benefits to its customers.

SUMMARY AND CONCLUSION

Q. Please summarize your testimony.

A. The wind repowering project presents the opportunity to leverage prior investments in the wind fleet and enhance its future value for customers. By executing wind turbine equipment purchases in late 2016, the Company was able to secure the opportunity to repower and renew the wind fleet and deliver the maximum value of these facilities to customers by qualifying for the full value of the PTC. Repowering now provides a unique opportunity to return the Company's wind turbines to like-new condition while enhancing their performance and avoiding expenditures that maintain but do not enhance the value of the wind fleet.

By incorporating recent technical advances that allow for longer blades to be installed on the existing towers and foundations, repowering will result in significantly more low-cost energy for customers—550 TWh annually, or an increase of 19 percent. With increases to the allowable transmission capacity of the facilities, these generation benefits will be 598 TWh, or an increase of 21 percent. If new equipment now being developed by GE for repowering projects can be successfully applied to these facilities, generation will be further increased with resulting benefits to customers. Further, repowering with new equipment will extend the asset lives of the wind facilities by at least 10 years—allowing the wind facilities to continue serving customers well into the future.

Finally, these benefits from repowering can be delivered to customers while reducing rather than increasing costs to customers, as further described by Company witness Mr. Link.

Q. What is your recommendation to the Commission?

A. I recommend the Commission enter a finding that the decision to repower certain wind facilities is prudent and in the public interest and approve the Application as filed, including the request for continued cost recovery of the wind equipment that will be replaced and the proposed rate-making treatment for the new costs and benefits of the wind repowering project.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

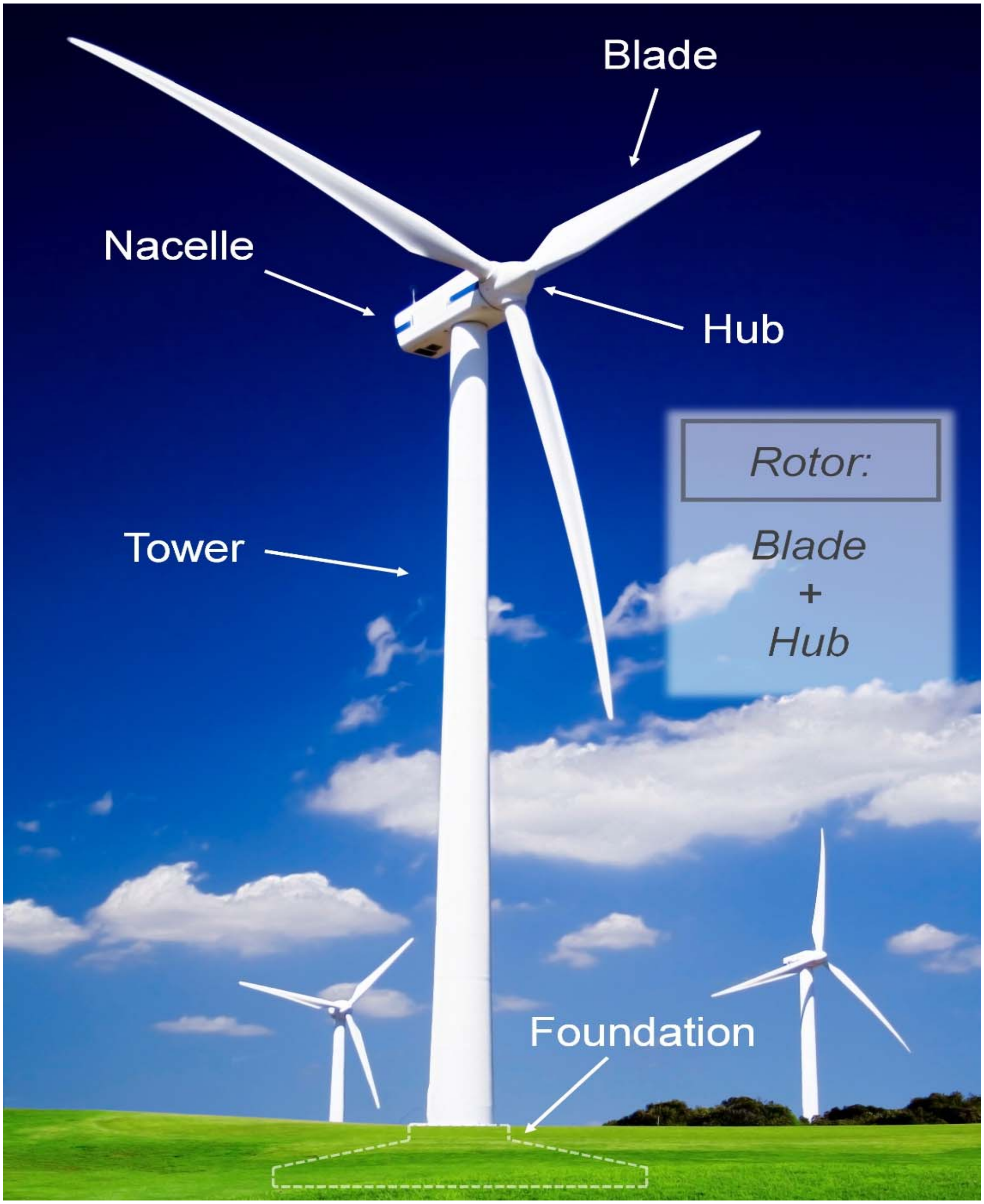
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Wind Turbine Component Diagram

June 2017

Major Components of a Wind Turbine Generator



Rocky Mountain Power
Exhibit RMP___(TJH-2)
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

List of Projects to be Repowered

June 2017

Exhibit RMP___TJH-2

PacifiCorp Wind Fleet Repowering

List of projects to be repowered

Project #	Wind Project	Location	Commercial Start Date	Years in Operation	Number of WTGs	Current Net Capacity (MW)	Current Long-Term Generation (MWh)
Wyoming Projects							
1	Glenrock I	Glenrock, WY	12/31/2008	8.5	66	99.0	303,723
2	Glenrock III	Glenrock, WY	1/17/2009	8.4	26	39.0	113,438
3	Rolling Hills	Glenrock, WY	1/17/2009	8.4	66	99.0	271,635
4	Seven Mile Hill I	Medicine Bow, WY	12/31/2008	8.5	66	99.0	339,195
5	Seven Mile Hill II	Medicine Bow, WY	12/31/2008	8.5	13	19.5	71,224
6	High Plains	McFadden, WY	9/13/2009	7.8	66	99.0	306,145
7	McFadden Ridge	McFadden, WY	9/29/2009	7.7	19	28.5	93,101
8	Dunlap I	Medicine Bow, WY	10/1/2010	6.7	74	111.0	389,045
					396	**594.0**	**1,887,506**
Washington Projects							
9	Marengo I	Dayton, WA	8/3/2007	9.9	78	140.4	360,279
10	Marengo II	Dayton, WA	6/26/2008	9.0	39	70.2	166,742
11	Goodnoe Hills	Goldendale, WA	5/31/2008	9.1	47	94.0	220,898
					164	**304.6**	**747,919**
Oregon Project							
12	Leaning Juniper	Arlington, OR	9/14/2006	10.8	67	100.5	233,592
					627	**999.1**	**2,869,016**

Annual generation from projects with PTCs expiring between August 2017 and October 2020 (MWh)	**2,635,424**
2017 PTC Value ($/MWh)	**$24.00**
PacifiCorp corporate tax rate	**37.95%**
Loss in customer PTC benefits with expiration of original PTCs from wind plants (2017$)	**$ 101,934,219**

REDACTED
Rocky Mountain Power
Exhibit RMP___(TJH-3)
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 Direct Testimony of Timothy J. Hemstreet

Repowering Capital Costs, In-Service Dates, and Energy Increases

June 2017

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

Rocky Mountain Power
Exhibit RMP___(TJH-4)
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

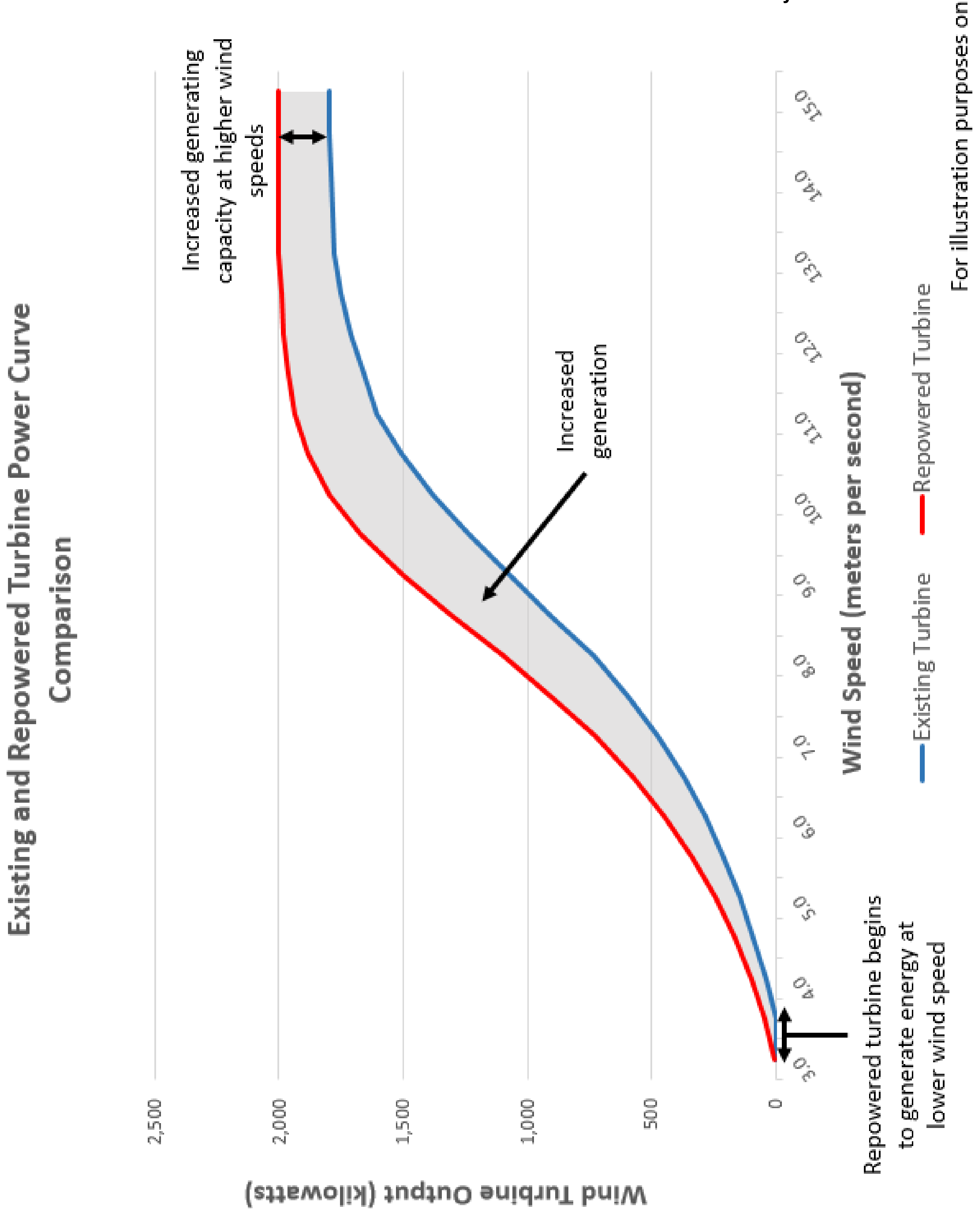
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Existing and Repowered Turbine Power Curve Comparison

June 2017


Existing and Repowered Turbine Power Curve Comparison
Wind Turbine Output (kilowatts)
0
500
1,000
1,500
2,000
2,500
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.0
11.0
12.0
13.0
14.0
15.0
Wind Speed (meters per second)
Existing Turbine
Repowered Turbine
Increased generating capacity at higher wind speeds
Increased generation
Repowered turbine begins to generate energy at lower wind speed
For illustration purposes only

Rocky Mountain Power
Exhibit RMP___(TJH-5)
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

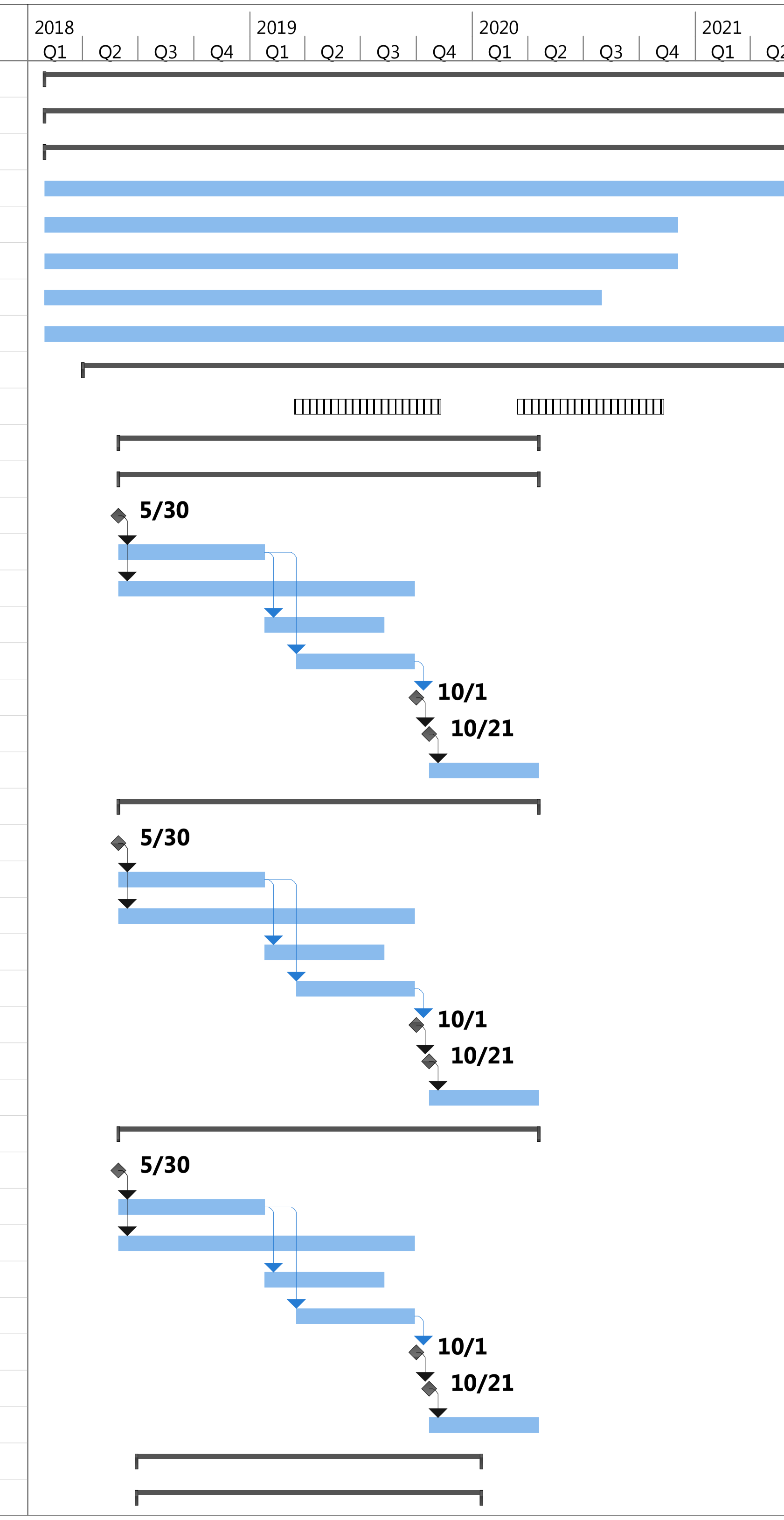
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Repower Schedule

June 2017

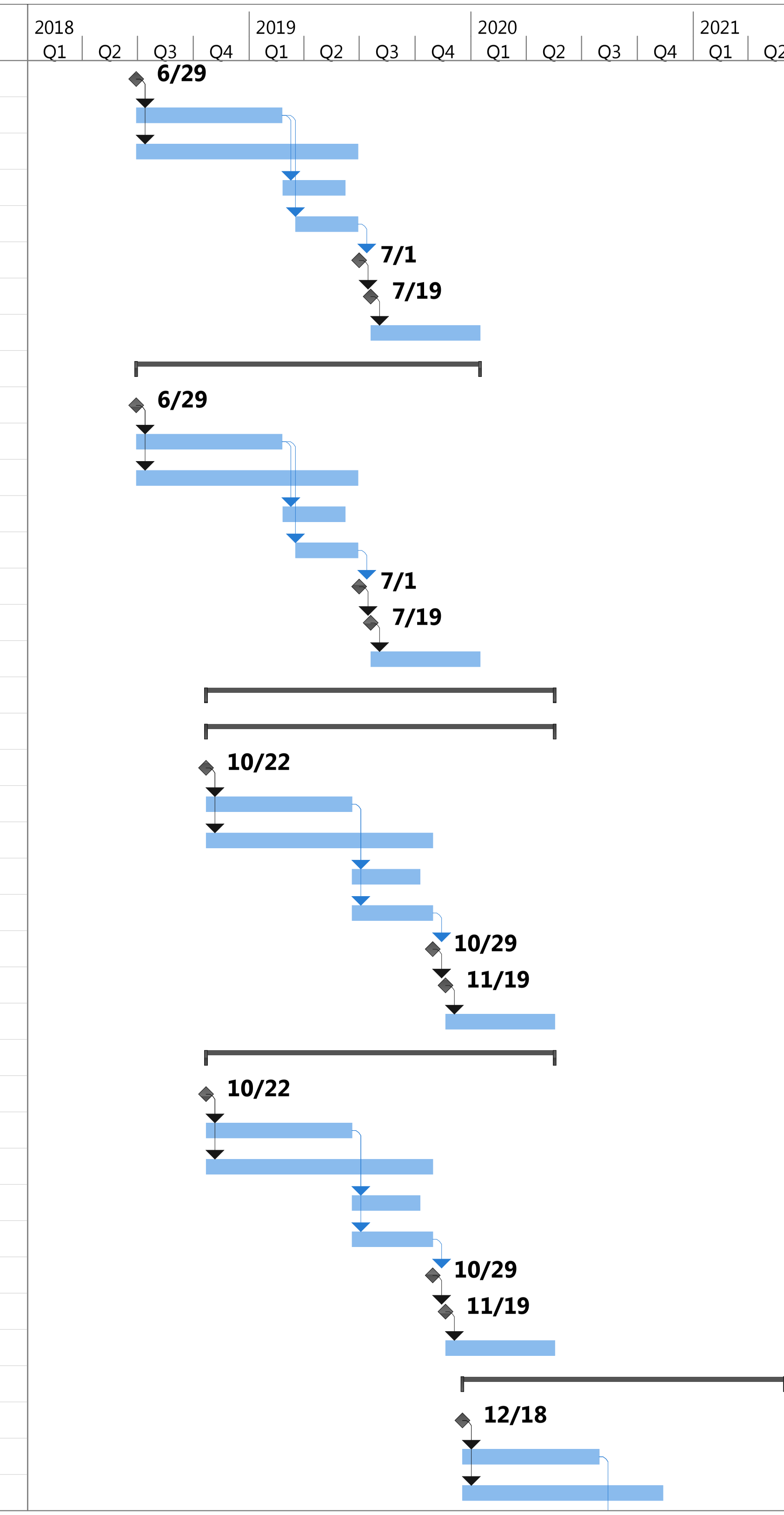
ID	Task Mode	Task Name	Start	Finish	Duration	Predecessors	Notes
1		**Repowering Project**	**Mon 1/29/18**	**Mon 5/31/21**	**871 days**		
2		**Program Execution**	**Mon 1/29/18**	**Mon 5/31/21**	**871 days**		
3		**Management**	**Mon 1/29/18**	**Mon 5/31/21**	**871 days**		
4		Project Management	Mon 1/29/18	Mon 5/31/21	871 days		
5		Engineering	Mon 1/29/18	Wed 12/2/20	743 days		
6		Environmental & Permitting	Mon 1/29/18	Wed 12/2/20	743 days		
7		Property	Mon 1/29/18	Thu 7/30/20	654 days		
8		Construction Management	Mon 1/29/18	Mon 5/31/21	871 days		
9		**Project Execution**	**Mon 4/2/18**	**Mon 5/31/21**	**826 days**		
10		**WTG Installation Periods**	**Fri 3/15/19**	**Tue 11/10/20**	**432 days**		
13		**Glenrock Area**	**Wed 5/30/18**	**Sat 4/18/20**	**493 days**		
14		**Glenrock I**	**Wed 5/30/18**	**Sat 4/18/20**	**493 days**		
15		Issue WTG Supply and Retrofit Contract Release(s)	Wed 5/30/18	Wed 5/30/18	0 days		
16		WTG Fabrication	Wed 5/30/18	Fri 1/25/19	8 emons	15	
17		Site Civil Works / BOP	Wed 5/30/18	Fri 9/27/19	348 days	15	
18		Transport and Delivery	Fri 1/25/19	Thu 8/8/19	28 wks	16	
19		WTG Installation	Mon 3/18/19	Fri 9/27/19	28 wks	16	
20		Substantial Completion	Tue 10/1/19	Tue 10/1/19	0 days	19	
21		Final Completion	Mon 10/21/19	Mon 10/21/19	0 days	20FS+15 days	
22		Project Closeout	Mon 10/21/19	Sat 4/18/20	6 emons	21	
23		**Glenrock III**	**Wed 5/30/18**	**Sat 4/18/20**	**493 days**		
24		Issue WTG Supply and Retrofit Contract Release(s)	Wed 5/30/18	Wed 5/30/18	0 days		
25		WTG Fabrication	Wed 5/30/18	Fri 1/25/19	8 emons	24	
26		Site Civil Works / BOP	Wed 5/30/18	Fri 9/27/19	348 days	24	
27		Transport and Delivery	Fri 1/25/19	Thu 8/8/19	28 wks	25	
28		WTG Installation	Mon 3/18/19	Fri 9/27/19	28 wks	25	
29		Substantial Completion	Tue 10/1/19	Tue 10/1/19	0 days	28	
30		Final Completion	Mon 10/21/19	Mon 10/21/19	0 days	29FS+15 days	
31		Project Closeout	Mon 10/21/19	Sat 4/18/20	6 emons	30	
32		**Rolling Hills**	**Wed 5/30/18**	**Sat 4/18/20**	**493 days**		
33		Issue WTG Supply and Retrofit Contract Release(s)	Wed 5/30/18	Wed 5/30/18	0 days		
34		WTG Fabrication	Wed 5/30/18	Fri 1/25/19	8 emons	33	
35		Site Civil Works / BOP	Wed 5/30/18	Fri 9/27/19	348 days	33	
36		Transport and Delivery	Fri 1/25/19	Thu 8/8/19	28 wks	34	
37		WTG Installation	Mon 3/18/19	Fri 9/27/19	28 wks	34	
38		Substantial Completion	Tue 10/1/19	Tue 10/1/19	0 days	37	
39		Final Completion	Mon 10/21/19	Mon 10/21/19	0 days	38FS+15 days	
40		Project Closeout	Mon 10/21/19	Sat 4/18/20	6 emons	39	
41		**Seven Mile Hill Area**	**Fri 6/29/18**	**Wed 1/15/20**	**404 days**		
42		**Seven Mile Hill I**	**Fri 6/29/18**	**Wed 1/15/20**	**404 days**		



Project: Repower Schedule
Date: Fri 6/16/17

Task | Split | Milestone | Summary | Project Summary

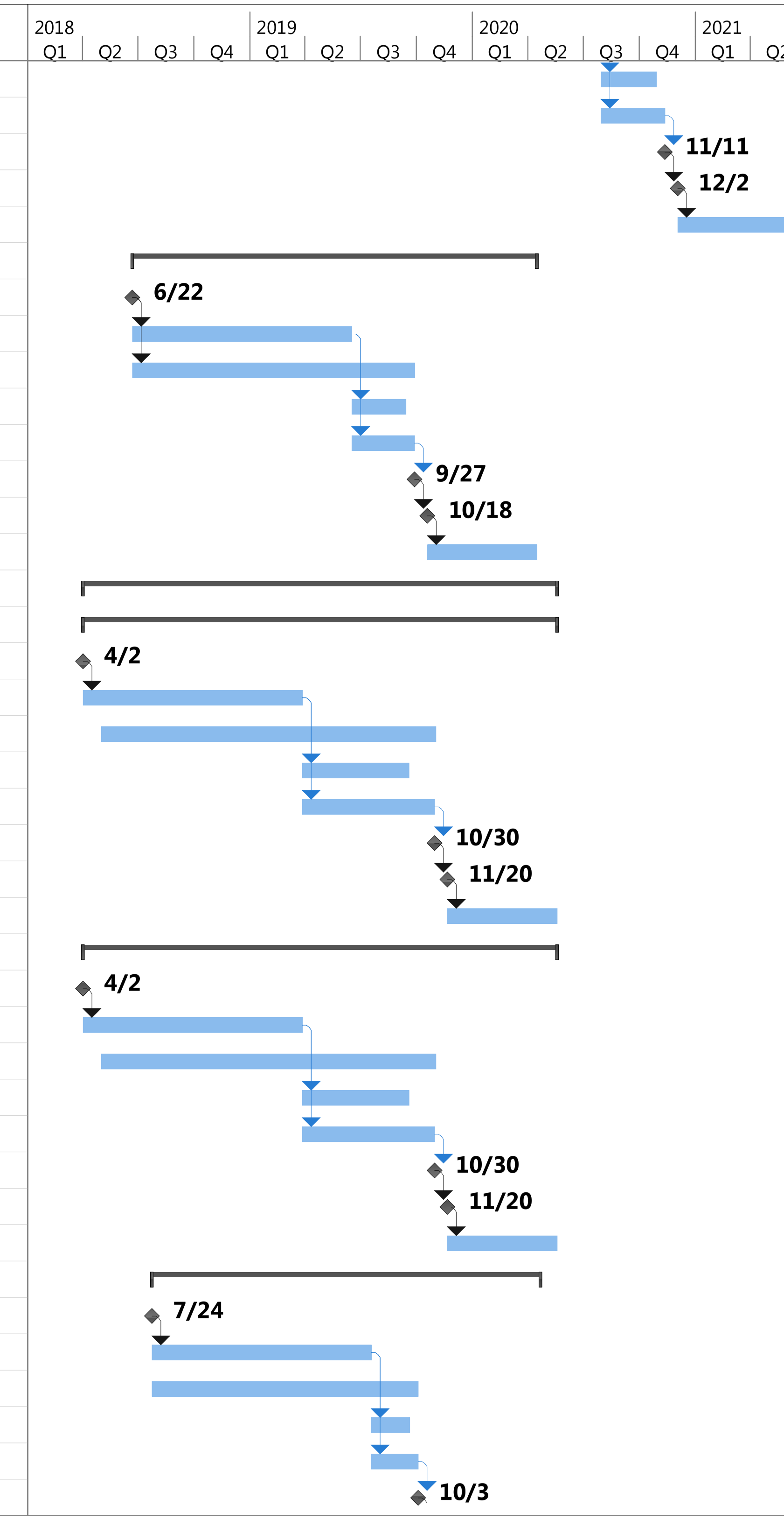
ID	Task Mode	Task Name	Start	Finish	Duration	Predecessors	Notes
43		Issue WTG Supply and Retrofit Contract Release(s)	Fri 6/29/18	Fri 6/29/18	0 days		
44		WTG Fabrication	Fri 6/29/18	Sun 2/24/19	8 emons	43	
45		Site Civil Works / BOP	Fri 6/29/18	Fri 6/28/19	261 days	43	
46		Transport and Delivery	Mon 2/25/19	Fri 6/7/19	15 wks	44	
47		WTG Installation	Mon 3/18/19	Fri 6/28/19	15 wks	44	
48		Substantial Completion	Mon 7/1/19	Mon 7/1/19	0 days	47	
49		Final Completion	Fri 7/19/19	Fri 7/19/19	0 days	48FS+15 days	
50		Project Closeout	Fri 7/19/19	Wed 1/15/20	6 emons	49	
51		**Seven Mile Hill II**	**Fri 6/29/18**	**Wed 1/15/20**	**404 days**		
52		Issue WTG Supply and Retrofit Contract Release(s)	Fri 6/29/18	Fri 6/29/18	0 days		
53		WTG Fabrication	Fri 6/29/18	Sun 2/24/19	8 emons	52	
54		Site Civil Works / BOP	Fri 6/29/18	Fri 6/28/19	261 days	52	
55		Transport and Delivery	Mon 2/25/19	Fri 6/7/19	15 wks	53	
56		WTG Installation	Mon 3/18/19	Fri 6/28/19	15 wks	53	
57		Substantial Completion	Mon 7/1/19	Mon 7/1/19	0 days	56	
58		Final Completion	Fri 7/19/19	Fri 7/19/19	0 days	57FS+15 days	
59		Project Closeout	Fri 7/19/19	Wed 1/15/20	6 emons	58	
60		**High Plains/McFadden Ridge Area**	**Mon 10/22/18**	**Sun 5/17/20**	**410 days**		
61		**High Plains**	**Mon 10/22/18**	**Sun 5/17/20**	**410 days**		
62		Issue WTG Supply and Retrofit Contract Release(s)	Mon 10/22/18	Mon 10/22/18	0 days		
63		WTG Fabrication	Mon 10/22/18	Wed 6/19/19	8 emons	62	
64		Site Civil Works / BOP	Mon 10/22/18	Tue 10/29/19	267 days	62	
65		Transport and Delivery	Wed 6/19/19	Tue 10/8/19	16 wks	63	
66		WTG Installation	Wed 6/19/19	Tue 10/29/19	19 wks	63	
67		Substantial Completion	Tue 10/29/19	Tue 10/29/19	0 days	66	
68		Final Completion	Tue 11/19/19	Tue 11/19/19	0 days	67FS+15 days	
69		Project Closeout	Tue 11/19/19	Sun 5/17/20	6 emons	68	
70		**McFadden Ridge**	**Mon 10/22/18**	**Sun 5/17/20**	**410 days**		
71		Issue WTG Supply and Retrofit Contract Release(s)	Mon 10/22/18	Mon 10/22/18	0 days		
72		WTG Fabrication	Mon 10/22/18	Wed 6/19/19	8 emons	71	
73		Site Civil Works / BOP	Mon 10/22/18	Tue 10/29/19	267 days	71	
74		Transport and Delivery	Wed 6/19/19	Tue 10/8/19	16 wks	72	
75		WTG Installation	Wed 6/19/19	Tue 10/29/19	19 wks	72	
76		Substantial Completion	Tue 10/29/19	Tue 10/29/19	0 days	75	
77		Final Completion	Tue 11/19/19	Tue 11/19/19	0 days	76FS+15 days	
78		Project Closeout	Tue 11/19/19	Sun 5/17/20	6 emons	77	
79		**Dunlap**	**Wed 12/18/19**	**Mon 5/31/21**	**379 days**		
80		Issue WTG Supply and Retrofit Contract Release(s)	Wed 12/18/19	Wed 12/18/19	0 days		
81		WTG Fabrication	Wed 12/18/19	Thu 7/30/20	7.5 emons	80	
82		Site Civil Works / BOP	Wed 12/18/19	Wed 11/11/20	236 days	80	



Project: Repower Schedule
Date: Fri 6/16/17

Task | Split | Milestone | Summary | Project Summary

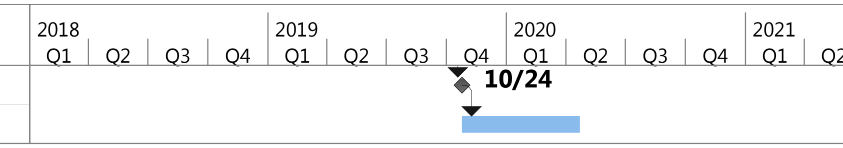
ID	Task Mode	Task Name	Start	Finish	Duration	Predecessors	Notes
83		Transport and Delivery	Thu 7/30/20	Wed 10/28/20	13 wks	81	
84		WTG Installation	Thu 7/30/20	Wed 11/11/20	15 wks	81	
85		Substantial Completion	Wed 11/11/20	Wed 11/11/20	0 days	84	
86		Final Completion	Wed 12/2/20	Wed 12/2/20	0 days	85FS+15 days	
87		Project Closeout	Wed 12/2/20	Mon 5/31/21	6 emons	86	
88		**Leaning Juniper**	**Fri 6/22/18**	**Wed 4/15/20**	**474 days**		
89		Issue WTG Supply and Retrofit Contract Release(s)	Fri 6/22/18	Fri 6/22/18	0 days		
90		WTG Fabrication	Fri 6/22/18	Mon 6/17/19	12 emons	89	
91		Site Civil Works / BOP	Fri 6/22/18	Fri 9/27/19	331 days	89	
92		Transport and Delivery	Mon 6/17/19	Fri 9/13/19	13 wks	90	
93		WTG Installation	Mon 6/17/19	Fri 9/27/19	15 wks	90	
94		Substantial Completion	Fri 9/27/19	Fri 9/27/19	0 days	93	
95		Final Completion	Fri 10/18/19	Fri 10/18/19	0 days	94FS+15 days	
96		Project Closeout	Fri 10/18/19	Wed 4/15/20	6 emons	95	
97		**Marengo Area**	**Mon 4/2/18**	**Mon 5/18/20**	**556 days**		
98		**Marengo I**	**Mon 4/2/18**	**Mon 5/18/20**	**556 days**		
99		Issue WTG Supply and Retrofit Contract Release(s)	Mon 4/2/18	Mon 4/2/18	0 days		
100		WTG Fabrication	Mon 4/2/18	Thu 3/28/19	12 emons	99	
101		Site Civil Works / BOP	Wed 5/2/18	Fri 11/1/19	393 days		
102		Transport and Delivery	Thu 3/28/19	Wed 9/18/19	25 wks	100	
103		WTG Installation	Thu 3/28/19	Wed 10/30/19	31 wks	100	
104		Substantial Completion	Wed 10/30/19	Wed 10/30/19	0 days	103	
105		Final Completion	Wed 11/20/19	Wed 11/20/19	0 days	104FS+15 day	
106		Project Closeout	Wed 11/20/19	Mon 5/18/20	6 emons	105	
107		**Marengo II**	**Mon 4/2/18**	**Mon 5/18/20**	**556 days**		
108		Issue WTG Supply and Retrofit Contract Release(s)	Mon 4/2/18	Mon 4/2/18	0 days		
109		WTG Fabrication	Mon 4/2/18	Thu 3/28/19	12 emons	108	
110		Site Civil Works / BOP	Wed 5/2/18	Fri 11/1/19	393 days		
111		Transport and Delivery	Thu 3/28/19	Wed 9/18/19	25 wks	109	
112		WTG Installation	Thu 3/28/19	Wed 10/30/19	31 wks	109	
113		Substantial Completion	Wed 10/30/19	Wed 10/30/19	0 days	112	
114		Final Completion	Wed 11/20/19	Wed 11/20/19	0 days	113FS+15 day	
115		Project Closeout	Wed 11/20/19	Mon 5/18/20	6 emons	114	
116		**Goodnoe Hills**	**Tue 7/24/18**	**Tue 4/21/20**	**456 days**		
117		Issue WTG Supply and Retrofit Contract Release(s)	Tue 7/24/18	Tue 7/24/18	0 days		
118		WTG Fabrication	Tue 7/24/18	Fri 7/19/19	12 emons	117	
119		Site Civil Works / BOP	Tue 7/24/18	Thu 10/3/19	313 days		
120		Transport and Delivery	Fri 7/19/19	Thu 9/19/19	9 wks	118	
121		WTG Installation	Fri 7/19/19	Thu 10/3/19	11 wks	118	
122		Substantial Completion	Thu 10/3/19	Thu 10/3/19	0 days	121	



Project: Repower Schedule
Date: Fri 6/16/17

Task | Split | Milestone | Summary | Project Summary

ID		Task Mode	Task Name	Start	Finish	Duration	Predecessors	Notes
123			Final Completion	Thu 10/24/19	Thu 10/24/19	0 days	122FS+15 day	
124			Project Closeout	Thu 10/24/19	Tue 4/21/20	6 emons	123	



Project: Repower Schedule
Date: Fri 6/16/17

Task Split Milestone Summary Project Summary

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
Direct Testimony of Rick T. Link

June 2017

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

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource and Commercial Strategy. I am testifying in this proceeding on behalf of Rocky Mountain Power, a division of PacifiCorp.

Q. Please describe your current responsibilities.

A. I am responsible for PacifiCorp's integrated resource plan ("IRP"), structured commercial business and valuation activities, long-term commodity price forecasts, long-term load forecasts, and environmental strategy and policy activities. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and for implementing competitive request for proposal ("RFP") processes consistent with applicable state procurement rules and guidelines.

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2016. From 2003 through 2016, I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, and 2017 IRPs, have been directly involved with implementing several resource RFP processes, and performed economic analysis supporting a range of resource investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

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

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present and explain the economic analysis that shows PacifiCorp's decision to upgrade, or "repower," certain wind resources is prudent and provides significant customer benefits. I also summarize PacifiCorp's assessment of the wind repowering project in its 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis supports repowering approximately 999 megawatts ("MW") of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional ten years of federal production tax credits ("PTCs"), produce more energy, reset the thirty-year depreciable life of the assets, and reduce run-rate operating costs. PacifiCorp's economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, net power cost ("NPC") benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

The change in revenue requirement due to wind repowering was analyzed across nine different scenarios, each with varying natural gas and carbon dioxide ("CO_2") price assumptions. All nine scenarios show customer benefits, as measured by the change in present-value revenue requirement over the remaining life of the repowered wind facilities. With medium natural gas and medium CO_2 price assumptions, the present-value change in revenue requirement due to wind repowering shows $359 million customer benefit. Across all nine scenarios, the change in present-value revenue requirement due to repowering ranges from $41 million in customer benefits when assuming low natural gas prices and zero CO_2 prices to $589 million when assuming high natural gas prices and high CO_2 prices. These benefits conservatively do not assign any value to the incremental renewable-energy credits ("RECs") that will be produced by the repowered wind facilities. Over the remaining life of the repowered wind facilities, present-value benefits would improve for all scenarios by an additional $11 million for every dollar assigned to the incremental RECs that will be generated after repowering.

When the present-value revenue requirement is measured over a 20-year period through 2036, PacifiCorp's economic analysis demonstrates net customer benefits in seven of nine natural gas and CO_2 price scenarios (all scenarios except the two using the lowest natural-gas price assumptions).

The wind repowering project will reduce revenue requirement soon after the new equipment is placed in service in the 2019-to-2020 time frame. From 2021 through

2028, revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. In his testimony, Mr. Jeffrey K. Larsen explains Rocky Mountain Power's proposal to reflect the benefits of wind repowering in rates.

Sensitivity analysis shows that benefits of wind repowering substantially increase when combined with new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission project, which are the subject of a concurrent application. Sensitivity analysis also shows that there is additional upside to customer benefits if the new equipment is depreciated over a longer life and if current large-generator interconnection agreements ("LGIAs") are modified to enable repowered wind facilities to operate at their full capacity.

2017 INTEGRATED RESOURCE PLAN

Q. Did PacifiCorp analyze wind repowering in its 2017 IRP?

A. Yes. The preferred portfolio in the 2017 IRP, representing PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, includes repowering of 905 MW of existing wind resource capacity located in Wyoming, Washington, and Oregon. As discussed later in my testimony, PacifiCorp expanded the wind repowering scope to include its Goodnoe Hills wind facility. With the addition of Goodnoe Hills, this application covers PacifiCorp's proposal to repower approximately 999 MW of existing wind capacity.

Q. What led PacifiCorp to evaluate the wind repowering opportunity in its 2017 IRP?

A. As explained by Mr. Timothy J. Hemstreet, PacifiCorp purchased safe-harbor equipment from General Electric International, Inc., and Vestas American Wind Technology, Inc., in December 2016. Consistent with Internal Revenue Service ("IRS") guidance, these equipment purchases, totaling $77.8 million, secured an option for PacifiCorp to repower its fleet of owned wind resources, thereby qualifying them for the full value of federal PTCs.

Wind repowering presents an opportunity to deliver several different types of benefits for customers. First, federal PTCs will apply to 10 additional years of generation from each repowered wind resource. The current value of federal PTCs, which is adjusted annually for inflation by the IRS, is $24 per megawatt-hour ("MWh"). At a federal and state effective tax rate of 37.95 percent, the current PTC equates to a $38.68 per MWh reduction in revenue requirement that can be passed through to customers.

Second, existing wind resources will be upgraded with modern technology, which improves efficiency and increases energy output. The additional energy output from these zero-fuel-cost assets provides incremental NPC benefits for customers.

Third, repowering a wind resource, which replaces the mechanical equipment of an existing wind facility, resets the usable life of the asset (currently 30 years), thereby extending and increasing NPC benefits over the period in which the repowered wind resource would have otherwise been retired from service.

Finally, the turbine-supply contracts for repowering will include a two-year warranty on the new equipment, which will avoid capital expenditures that would otherwise be needed to replace or refurbish existing equipment. Moreover, PacifiCorp anticipates that new, modern equipment will have reduced failure rates. Further, before installing the new equipment, PacifiCorp can avoid capital replacement costs for component failures on the existing equipment. This cost savings will be partially offset by lost energy output for specific wind turbines from the time that component failures occur through the time that the new equipment is installed.

After executing its safe-harbor equipment purchase in December 2016, PacifiCorp developed a wind repowering sensitivity in the first quarter of 2017, for consideration in its 2017 IRP, to evaluate the net customer benefits of the wind repowering opportunity.

Q. What wind resources did PacifiCorp include in the wind repowering sensitivity presented in its 2017 IRP?

A. PacifiCorp assumed repowering 905 MW of existing wind resource capacity in the 2017 IRP. Of the 905 MW, approximately 594 MW of this capacity are located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plans, McFadden Ridge, and Dunlap), approximately 101 MW are located in Oregon (Leaning Juniper), and approximately 210 MW are located in Washington (Marengo). PacifiCorp has since expanded its economic analysis to include Goodnoe Hills, which is located in Washington.

Q. What were the results of the wind repowering sensitivity presented in PacifiCorp's 2017 IRP?

A. The 2017 IRP wind repowering sensitivity showed significant net customer benefits across a range of assumptions related to forward market prices and federal CO_2 policy based on the Clean Power Plan ("CPP").

Q. Did the wind repowering sensitivity influence selection of the preferred portfolio in the 2017 IRP?

A. Yes. The wind repowering sensitivity included in the 2017 IRP showed significant net customer benefits by lowering the projected system present-value revenue requirement ("PVRR") relative to other resource portfolio options. Consequently, wind repowering was included in the 2017 IRP preferred portfolio, which represents PacifiCorp's plan to deliver reliable and reasonably priced service with manageable risk for customers through specific action items.

Q. Did PacifiCorp include a wind repowering action item in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan, which lists the specific steps PacifiCorp will take over the next two to four years to deliver resources in the preferred portfolio, includes the following action item:

> PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016.
>
> - Continue to refine and update economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed.
> - By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills).
> - Pursue regulatory review and approval as necessary.
> - By May 2018, issue the engineering, procurement and construction (EPC) notice to proceed to begin implementing wind repowering for specific projects consistent with updated financial analysis.
> - By December 31, 2020, complete installation of wind repowering equipment on all identified projects.[1]

Q. Please summarize PacifiCorp's progress with this action item.

A. PacifiCorp refined and updated its economic analysis of plant-specific wind repowering opportunities, and is now including Goodnoe Hills in the wind repowering project. The rest of my testimony presents and explains this economic analysis.

[1] PacifiCorp 2017 Integrated Resource Plan, Volume I at 16 (Apr. 4, 2017).

Mr. Hemstreet explains that PacifiCorp continues to evaluate repowering of the Foote Creek facility in Wyoming, but due to differences in project scope for this older-vintage facility, Foote Creek is not proposed as part of the wind repowering project in this application. Mr. Hemstreet also discusses the need to execute contracts by early April 2018 and addresses the construction schedule.

SYSTEM MODELING METHODOLOGY

Q. Please summarize the methodology PacifiCorp used in its system analysis of the wind repowering project.

A. PacifiCorp relied upon the same modeling tools used to develop and analyze resource portfolios in its 2017 IRP to refine and update its analysis of the wind repowering project. These modeling tools calculate system PVRR by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the present-value revenue requirement differential ("PVRR(d)") between two simulations of PacifiCorp's system. One simulation includes the wind repowering project and the other simulation excludes the wind repowering project. Customers are expected to realize benefits when the system PVRR with wind repowering is lower than the system PVRR without repowering. Conversely, customers would experience increased costs if the system PVRR with wind repowering were higher than the system PVRR without wind repowering.

Q. What modeling tools did PacifiCorp use to perform its system analysis of the wind repowering project?

A. PacifiCorp used the System Optimizer ("SO") model and the Planning and Risk model ("PaR") to develop resource portfolios and to forecast dispatch of system resources in simulations with and without wind repowering.

Q. Please describe the SO model and PaR.

A. The SO model is used to develop resource portfolios with sufficient capacity to achieve a target planning-reserve margin. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system PVRR. In selecting the least-cost resource portfolio for a given set of input assumptions, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective demand-side-management ("DSM") resources—all within or connected to PacifiCorp's system. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable operations and maintenance, and emissions, as applicable), the cost of new DSM resources, and levelized revenue requirement of capital additions for existing coal resources and potential new generating resources.

PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves, volatility and uncertainty in key system variables. PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results. The PVRR from the PaR model reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable operations and maintenance costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed operations and maintenance costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

Q. How has PacifiCorp historically used the SO model and PaR?

A. PacifiCorp uses the SO model and PaR to produce and evaluate resource portfolios in its IRP. PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects. The models were used to support the successful acquisition of the Chehalis combined-cycle plant, to support selection of the Lake Side 2 combined-cycle resource through a RFP process, and to evaluate installation of emissions control equipment. These models will also be used to evaluate bids in the soon-to-be-issued 2017R RFP, which is being issued to solicit bids for new wind resources.

Q. Are the SO model and PaR the appropriate tools for analyzing the wind repowering opportunity?

A. Yes. The SO model and PaR are the appropriate modeling tools when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the wind repowering project. PaR provides additional granularity on how wind repowering is projected to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for the wind repowering opportunity that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP.

Q. How did PacifiCorp use PaR to assess stochastic system cost risk associated with wind repowering?

A. Just as it evaluates resource-portfolio alternatives in the IRP, PacifiCorp uses the stochastic-mean PVRR and risk-adjusted PVRR, calculated from PaR study results, to assess the stochastic system cost risk of repowering. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp uses a risk-adjusted PVRR to evaluate stochastic system cost risk. The risk-adjusted PVRR incorporates the expected value of low-probability, high-cost outcomes. The risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95^{th} percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to the wind repowering analysis, the stochastic-mean PVRR represents the expected level of system costs from cases with and without repowering.

The risk-adjusted PVRR is used to assess whether wind repowering causes a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the wind repowering project?

A. Yes. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the wind-repowering project under a range of assumptions regarding wholesale market prices and CO_2 policy ("price-policy") assumptions. These assumptions drive NPC-related benefits, and so it is important to understand how the net-benefit analysis is affected under a range of potential outcomes. PacifiCorp developed low, medium, and high scenarios for the market price of electricity and natural gas and zero, medium, and high CO_2 price scenarios. Each pair of model simulations—with and without repowering, in both the SO model and PaR—was analyzed under each combination of these price-policy assumptions. I summarize the assumptions for each price-policy scenario later in my testimony.

PacifiCorp also completed three sensitivity studies to assess how certain factors affect the net benefits of the wind repowering project. The first sensitivity quantifies how the net benefits of the project are affected by the depreciable life of repowered facilities. PacifiCorp's base analysis assumes that repowering will reset the 30-year depreciable life of the asset. Assuming the possibility that wind facilities with modern equipment might continue operating over a longer period, this sensitivity quantifies the economic impact if the depreciable life of new equipment on a repowered facility were reset at 40 years.

The second sensitivity quantifies how the net benefits of wind repowering are affected when combined with 1,180 MW of new Wyoming wind resources (860 MW of owned resources and 320 MW of contracted resources) and the Aeolus-to-Bridger/Anticline transmission project. Consistent with PacifiCorp's application for a certificate for public convenience and necessity for the new wind and transmission assets (filed concurrent with this wind repowering application), this sensitivity assumes the new wind and transmission is operational by the end of October 2020.

The third sensitivity builds on the new-wind-and-transmission sensitivity case by assessing how the net benefits of wind repowering are affected if the repowered facilities are able to operate at their full generating capability. This sensitivity assumes the additional capacity and energy is combined with the new wind and new transmission included in the prior sensitivity. As described by Mr. Hemstreet, PacifiCorp's base analysis assumes that the repowered wind facilities continue to operate within the limits of their existing LGIAs. The average incremental energy output is expected to increase by approximately 19.2 percent if the repowered facilities operate within their existing LGIA limits. If these limits are modified, the average incremental energy output rises to 20.8 percent. PacifiCorp is studying whether these LGIAs can be modified to increase incremental energy output from the repowered facilities, which would increase the net benefits of repowering.

Q. How did PacifiCorp assess which wind facilities to include in the scope of the wind repowering project in this application?

A. PacifiCorp completed a series of SO model and PaR studies to determine how the system PVRR changes when a specific wind facility is added or removed from the scope of the wind repowering project. Starting with the wind repowering scope assumed in the 2017 IRP preferred portfolio, covering 905 MW of existing wind resource capacity, PacifiCorp first removed the Leaning Juniper facility from the wind repowering scope because it has the lowest expected annual average capacity factor among the owned wind facilities in PacifiCorp's wind fleet. A wind facility's capacity factor is a strong indicator of whether repowering is cost-effective because it is representative of energy output and is therefore tied to the amount of PTCs that will be generated if the facility is repowered. The risk-adjusted system PVRR from the case eliminating Leaning Juniper from the wind repowering project scope was $7 million higher than the risk-adjusted system PVRR from the case including Leaning Juniper in the project scope. Based on these results, Leaning Juniper remains within the scope of the wind repowering project considered in this application.

Because repowering of the Leaning Juniper facility, which has the lowest expected annual capacity factor relative to other wind facilities in PacifiCorp's fleet, provides incremental net benefits, all remaining wind facilities within the project scope would generate more PTCs and provide even larger incremental net benefits if repowered. Consequently, PacifiCorp did not analyze any further reductions to the wind repowering scope beyond its analysis of Leaning Juniper.

PacifiCorp next evaluated how expanding the wind repowering scope to include Goodnoe Hills would affect the system PVRR. The risk-adjusted system PVRR from the case including Goodnoe Hills in the project scope was $20 million lower than the system PVRR from the case without Goodnoe Hills. Based on these results, Goodnoe Hills was added to the repowering project scope considered in this application. With

Goodnoe Hills included, the scope of the repowering project considered in this application covers 999.1 MW of existing wind capacity—594 MW of this capacity is located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plans, McFadden Ridge, and Dunlap), 100.5 MW is located in Oregon (Leaning Juniper), and 304.6 MW is located in Washington (Marengo and Goodnoe Hills).

Q. What key assumptions did PacifiCorp update since analyzing the wind repowering project in its 2017 IRP?

A. Beyond the price-policy assumptions used to analyze a range of NPC-related benefits, the updated wind repowering analysis reflects updated assumptions for up-front capital costs, run-rate operating costs, and energy output for both the existing and repowered wind facilities. PacifiCorp's analysis assumes an up-front capital investment totaling approximately $1.13 billion with a 19.2 percent average increase in annual energy output. The cost and performance assumptions for the wind facilities studied for this application are summarized in Confidential Exhibit RMP___(RTL-1).

Q. How did PacifiCorp model de-rates to its Wyoming 230-kV transmission system when evaluating the wind repowering project?

A. In its final 2017 IRP resource-portfolio screening process, PacifiCorp identified and quantified reliability benefits associated with the Aeolus-to-Bridger/Anticline transmission project. This new transmission project would eliminate de-rates caused by outages on 230-kV transmission system elements. Historical outages on this part of PacifiCorp's transmission system indicate an average de-rate of 146 MW over approximately 88 outage days per year, which equates to approximately one 146-MW, 24-hour outage every four days. Without knowing when these events might occur, de-rates on the existing 230-kV transmission system were captured in the SO model and PaR as a 36.5 MW reduction in the transfer capability from eastern Wyoming to the Aeolus area. In the sensitivity performed to quantify how the net benefits of wind repowering are affected when combined with new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission project, this de-rate assumption was eliminated when the new transmission project is assumed to be placed in service at the end of October 2020.

Q. How did PacifiCorp model line-loss benefits associated with the Aeolus-to-Bridger/Anticline transmission project when studying the wind repowering project?

A. Line-loss benefits are only applicable if the Aeolus-to-Bridger/Anticline transmission project is built and therefore were only considered in the sensitivity performed to quantify how the net benefits of wind repowering are affected when combined with new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission project. For this sensitivity, when the Aeolus-to-Bridger/Anticline transmission project is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental 11.6 average MW ("aMW") of energy, which equates to approximately 102 gigawatt hours ("GWh"), will be able to flow out of eastern Wyoming each year. The line-loss benefit was reflected in the SO model and PaR by reducing northeast Wyoming load by approximately 11.6 aMW each year.

Q. Did PacifiCorp analyze potential energy imbalance market ("EIM") benefits in its wind repowering analysis?

A. Yes. In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the EIM can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the wind repowering analysis by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the wind repowering project; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Q. How did PacifiCorp account for the unrecovered investments in the original equipment that will be replaced with new equipment?

A. The economic analysis assumes that PacifiCorp will fully recover the unrecovered investment in the original equipment and earn its authorized rate of return on the unrecovered balance over the remainder of the original 30-year depreciable life of each repowered facility. Mr. Larsen describes PacifiCorp's proposed accounting treatment for the replaced equipment.

Q. Did PacifiCorp assume any salvage value for the equipment that will be replaced with repowering?

A. No. But any salvage value for the existing equipment would decrease the unrecovered investment and increase customer benefits.

ANNUAL REVENUE REQUIREMENT MODELING METHODOLOGY

Q. In addition to the system modeling used to calculate present-value net benefits over a twenty-year planning period, has PacifiCorp forecasted the change in nominal-annual revenue requirement due to the wind repowering project?

A. Yes. The system PVRR from the SO model and PaR is calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*e.g.*, NPC, fixed operations and maintenance) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of repowering, project capital costs need to be considered in nominal terms (*i.e.*, not levelized).

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

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates.

Consider the potential implications of modeling nominal capital revenue requirement for a future generating resource needed in 2036, the last year of the 2017 IRP planning period. If nominal capital revenue requirement were assumed, the model would capture in its economic assessment of resource alternatives the highest, first-year revenue requirement capital cost without having any foresight on the potential benefits that resource would provide beyond 2036. If nominal capital costs were applied, the model's economic assessment of resource alternatives for the 2036 resource need would inappropriately favor less capital-intensive projects or projects having longer asset lives, even if those alternatives would increase system costs over their remaining life. Levelized capital costs for assets that have different lives and in-service dates is an established way to address these types of distortions in the comparative economic analysis of resource alternatives.

Q. How did PacifiCorp forecast the annual revenue-requirement impacts of the wind repowering project?

A. In the models that exclude repowered wind, the annual stream of costs for wind facilities that are within the wind repowering scope, including levelized capital, are removed from the annual stream of costs used to calculate the stochastic-mean system PVRR. Similarly, in the simulation that includes repowered wind, the annual stream of costs for repowered wind facilities, including levelized capital and PTCs, are temporarily removed from the annual stream of costs used to calculate the stochastic-mean PVRR. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the wind facilities that are within the wind repowering scope, represents the net system benefit caused by the wind repowering project.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable operations and maintenance and emissions costs for those scenarios that include a CO_2 price assumption), and fixed-cost benefits. To complete the annual revenue-requirement forecast, the change in fixed costs for those wind facilities included in the wind repowering scope, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by wind repowering.

Q. Over what time frame did PacifiCorp estimate the change in annual revenue requirement due to the wind repowering project?

A. The change in annual revenue requirement was estimated through 2050. This captures the full 30-year life of the new equipment installed on repowered wind facilities.

Q. How did PacifiCorp calculate the net annual benefits caused by wind repowering beyond the 20-year forecast period used in PaR?

A. The PaR forecast period runs from 2017 through 2036. The change in net system benefits caused by wind repowering over the 2028-through-2036 time frame, expressed in dollars-per-MWh of incremental energy output from wind repowering, were used to estimate the change in system net benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by wind repowering were divided by the change in incremental energy expected from the wind repowering project, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the repowered wind projects over the 2028-through-2036 time frame were levelized. These levelized results were extended out through 2050 at inflation. The levelized net system benefits per MWh of incremental energy output from the repowered wind projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from repowered wind projects over the same period.

Q. Why did PacifiCorp use PaR results from the 2028-through-2036 time frame to extend system cost impacts out through 2050?

A. Consistent with the 2017 IRP, PacifiCorp's wind repowering analysis assumes the Dave Johnston coal plant, located in eastern Wyoming, retires at the end of 2027. When this plant is assumed to retire, transmission congestion affecting energy output from resources in eastern Wyoming, where many repowered wind resources are located, is reduced. The incremental energy output from repowered wind resources provides more system benefits when not constrained by transmission limitations. Consequently, the net system benefits caused by wind repowering over the 2028-through-2036 time frame, after Dave Johnston is assumed to retire, is representative of net system benefits that could be expected beyond 2036.

Q. Did PacifiCorp calculate a PVRR(d) for the wind repowering project using its estimate of annual revenue-requirement impacts projected out through 2050?

A. Yes.

Q. Does the PVRR(d) calculated from estimated annual revenue requirement through 2050 capture wind repowering benefits not included in the PVRR(d) calculated from the 20-year forecast coming out of the SO model and PaR ?

A. Yes. The PVRR(d) calculated off of estimated annual revenue requirement extended out through 2050 captures the significant increase in projected wind energy output beyond the 20-year forecast period.

Q. Why is there a significant increase in projected wind energy output beyond the 20-year forecast period ending 2036?

A. The change in wind energy output between cases with and without repowering experiences a step change in the 2036-through-2040 time frame, when the wind facilities, originally placed in-service during the 2006-through-2010 time frame, would otherwise have hit the end of their depreciable life. Before the 2036-through-2040 time frame, the change in wind energy output reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, the change in wind energy output between a case with and without repowering reflects the full energy output from the repowered wind facilities that would otherwise be retired.

PRICE-POLICY SCENARIOS

Q. Please explain why price-policy scenarios are important when analyzing the wind repowering project.

A. Wholesale-power prices, often set by natural gas prices, and the system cost impacts of potential CO_2 policies influence the forecast of net system benefits from wind repowering. Wholesale-power prices and CO_2 policy outcomes affect the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable cost benefits, and system fixed-cost benefits of wind repowering. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the wind repowering analysis, PacifiCorp studied the economics of the wind repowering project under a range of different price-policy scenarios.

Q. What price-policy scenarios did PacifiCorp use in its wind repowering analysis?

A. PacifiCorp analyzed the wind repowering project under nine different price-policy scenarios. PacifiCorp developed three wholesale-power price scenarios (low, medium, and high), and similarly developed three CO_2 policy scenarios (zero, medium, and high). The nine price-policy scenarios developed for the wind repowering analysis reflect different combinations of these scenario assumptions.

Considering that there is a high level of correlation between wholesale-power prices and natural gas prices, the wholesale-power price scenarios were based on a range of natural gas price assumptions. This ensures consistency between power price and natural gas price assumptions for each scenario. PacifiCorp implemented its CO_2 policy assumptions through a CO_2 price, expressed in dollars-per-ton.

While it is unlikely that the CPP will be implemented in its current form, it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emission reductions. CO_2 price assumptions used in the price-policy scenarios are not intended to mimic a specific type of policy mechanism (*i.e.*, a tax or an allowance price under a cap-and-trade program), but are intended to recognize that there might be future CO_2 policies that impose a cost to reduce emissions. Table 1 summarizes the nine price-policy scenarios used to analyze the wind repowering project.

Table 1. Price-Policy Scenarios

Price-Policy Scenario	Natural-Gas Prices (Levelized $/MMBtu)*	CO_2 Price Description
Low Gas, Zero CO_2	$3.19	$0/ton
Low Gas, Medium CO_2	$3.19	$3.41/ton in 2025 growing to $14.40/ton in 2036
Low Gas, High CO_2	$3.19	$4.73/ton in 2025 growing to $38.42/ton in 2036
Medium Gas, Zero CO_2	$4.07	$0/ton
Medium Gas, Medium CO_2	$4.13	$3.41/ton in 2025 growing to $14.40/ton in 2036
Medium Gas, High CO_2	$4.13	$4.73/ton in 2025 growing to $38.42/ton in 2036
High Gas, Zero CO_2	$5.83	$0/ton
High Gas, Medium CO_2	$5.83	$3.41/ton in 2025 growing to $14.40/ton in 2036
High Gas, High CO_2	$5.83	$4.73/ton in 2025 growing to $38.42/ton in 2036

*Nominal levelized Henry Hub natural-gas price from 2018 through 2036.

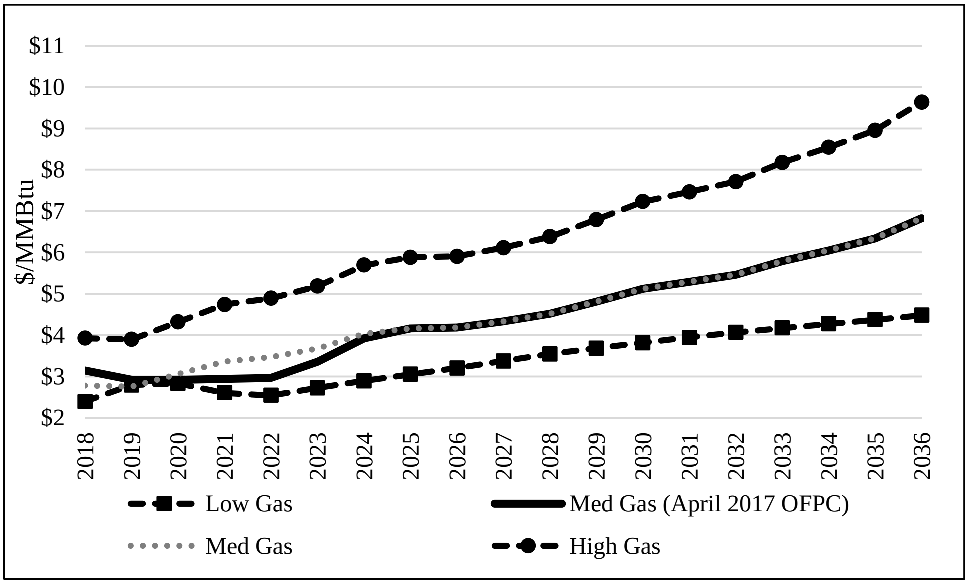
Q. Please describe the natural gas price assumptions used in the price-policy scenarios.

A. The medium-natural-gas-price assumptions that are paired with zero CO_2 prices reflect natural gas prices from PacifiCorp's official forward price curve ("OFPC") dated April 26, 2017. The OFPC uses observed forward market prices as of April 26, 2017, for 72 months, followed by a 12-month transition to natural gas prices based on a forecast developed by [redacted]. The medium, low, and high natural gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts developed by [redacted], and the U.S. Department of Energy's Energy Information Administration. Exhibit RMP___(RTL-2) shows the range in natural gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the wind repowering project.

The low-natural-gas-price assumption was derived from a low-price scenario developed by [redacted], which is based on surging growth in price-inelastic associated gas, technology improvements, stagnant liquefied natural gas exports, and an ever-expanding resource base. The medium-natural-gas-price assumption, which is used beyond month 84 in the April 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from [redacted] that is reasonably aligned with other base-case forecasts. The high-natural-gas-price assumption was based on a high-price scenario from [redacted]. The high-price scenario is based on risk aversion, whereby natural gas developers are reluctant to commit capital before demand, and the associated price response, materializes. This gives rise to exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in the third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

Figure 1 shows Henry Hub natural gas price assumptions from the April 2017 OFPC, low, medium, and high natural gas price scenarios. The April 2017 OFPC forecast only differs from the medium-natural-gas-price assumption in that it reflects observed market forwards through the first 72 months followed by a 12-month transition to [redacted] base-case forecast.

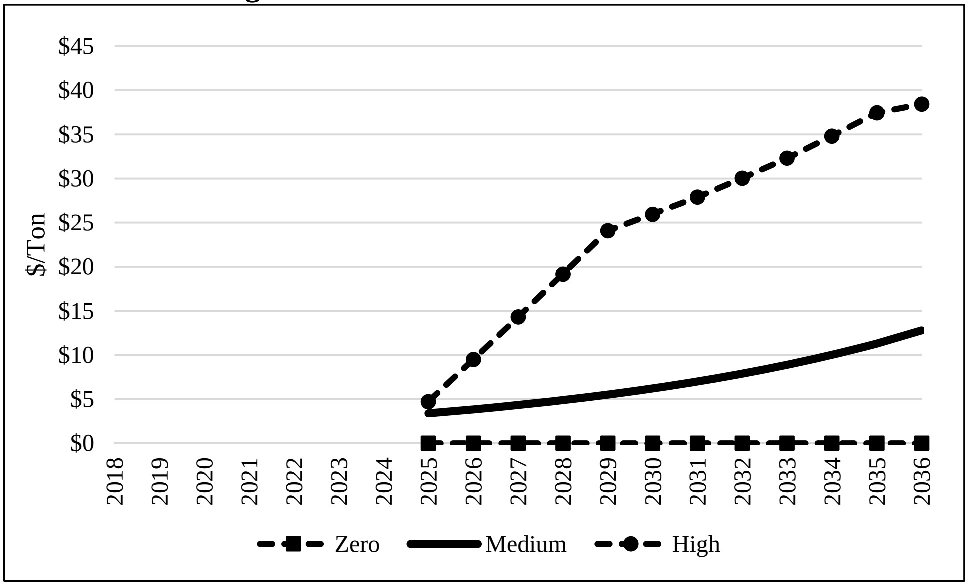
Figure 1. Nominal Natural Gas Price Scenarios



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

A. As with natural gas prices, the medium and high CO_2 price assumptions are based on third-party projections from [redacted]. Both forecasters assume CO_2 prices start in 2025. To bracket the low end of potential policy outcomes, PacifiCorp assumes there are no future policies adopted that would require incremental costs to achieve emissions reductions in the electric sector. In this scenario, the assumed CO_2 price is zero. Figure 2 shows the three CO_2 price assumptions used to analyze the wind repowering project.

Figure 2. Nominal CO_2 Price Scenarios



SYSTEM MODELING PRICE-POLICY RESULTS

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

A. Table 2 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown from the SO model and from PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-3).

Table 2. 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	$33	$43	$44
Low Gas, Medium CO_2	$0	$9	$8
Low Gas, High CO_2	($18)	($17)	($19)
Medium Gas, Zero CO_2	($33)	($24)	($25)
Medium Gas, Medium CO_2	($22)	($13)	($15)
Medium Gas, High CO_2	($41)	($35)	($36)
High Gas, Zero CO_2	($75)	($40)	($43)
High Gas, Medium CO_2	($64)	($34)	($37)
High Gas, High CO_2	($103)	($80)	($85)

Over a 20-year period, before accounting for the increase in incremental energy output beyond 2036, the wind repowering project reduces customer costs in seven out of nine price-policy scenarios. This trend occurs in the PVRR(d) calculated from both the SO model and PaR. The only price-policy scenarios without net customer benefits are those assuming the lowest natural gas prices when paired with either medium or zero CO_2 price assumptions. The PVRR(d) results show customer benefits under the price-policy scenario with low natural gas prices and high CO_2 prices, in all three of the medium-natural-gas-price scenarios, and in all three of the high-natural-gas-price scenarios. Under the central price-policy scenario, assuming medium-natural-gas prices and medium CO_2 prices, the PVRR(d) benefits range between $13 million, when based upon PaR-stochastic-mean results, and $22 million, when based upon SO model results.

The PVRR(d) results show that the benefits of the wind repowering project increase with natural gas prices and CO_2 prices. PVRR(d) results for scenarios where medium CO_2 prices are assumed with medium or high natural gas prices show a slight drop in benefits relative the zero-CO_2-price scenarios. This tends to be driven by changes to the timing of new resources in the outer years of the 20-year forecast period and would not likely persist if longer simulation periods were feasible.

Q. Is there incremental customer upside to the PVRR(d) results calculated from the SO and PaR models through 2036?

A. Yes. The PVRR(d) results presented in Table 2 do not reflect the potential value of RECs generated by the incremental wind energy output from the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $4 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2036.

Q. Why do the PaR results tend to show a different level of benefits from the wind repowering project when compared to the results from the SO model?

A. The two models assess the system impacts of the wind repowering project in different ways. The SO model is designed to dynamically assess system dispatch, with less granularity than PaR, while optimizing the selection of resources to the portfolio over time. PaR is able to dynamically assess system dispatch, with more granularity than the SO model and with consideration of stochastic risk variables; however, PaR does not modify the type, timing, size and location of resources in the portfolio in response to its more detailed assessment of system dispatch. In evaluating differences in annual system costs between the two models, PaR's ability to better simulate system dispatch relative to the SO model results in lower benefits from repowering being reported from PaR in the earlier years of the forecast horizon. Because PaR cannot modify resource selections in response to its assessment of system dispatch, this effect is softened over the longer term, when changes to the resource portfolio in response to wind repowering are more notable.

Q. Does one of these two models provide a better assessment of the wind repowering project relative to the other?

A. No. The two models are simply different, and both are useful in establishing a range of wind repowering benefits through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across the same set of price-policy scenarios with consistent trends in the difference in PVRR(d) results between price-policy scenarios. The consistency in the trend of forecasted benefits between the two models, each having its own strengths, shows that the wind repowering benefits are robust across a range of price-policy assumptions and when analyzed using different modeling tools.

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

A. The risk-adjusted PVRR(d) results are very similar to the stochastic-mean PVRR(d) results. This indicates that the wind repowering project does not materially affect high-cost, low-probability outcomes that can occur due to volatility in stochastic variables like load, wholesale-market prices, hydro generation, and thermal-unit outages.

Q. Did PacifiCorp review how repowered wind facilities located in Wyoming affect the dispatch of Wyoming coal plants?

A. Yes. After repowering, the incremental energy output from the repowered wind facilities located in Wyoming could contribute to additional transmission congestion and require re-dispatch of coal resources in the region. Re-dispatch of coal resources can reduce NPC-related benefits in those hours where increased congestion would restrict the otherwise economic use of these assets to serve load or as a source for wholesale-market sales. To assess the potential level of re-dispatch that might be associated with repowering, PacifiCorp reviewed the modeled changes in Wyoming coal generation.

Confidential Figure 3 summarizes the change in annual coal generation from Wyoming coal resources due to wind repowering for the medium-natural-gas-and-medium-CO_2 price-policy scenario. The figure shows that re-dispatch of Wyoming coal resources leads to [redacted], when component failures on existing wind resource equipment is assumed to reduce output for specific wind turbines until the new equipment is installed. After the wind repowering project is completed, re-dispatch leads to [redacted] the Dave Johnston plant and Jim Bridger Unit 3 are assumed to retire at the end of 2027 and 2028, respectively. Between 2021 and 2028, average annual coal generation for PacifiCorp's ownership interest in Wyoming coal resources [redacted]. In the later years of the forecast period, changes in coal generation are influenced by changes to the resource portfolio. Wyoming coal plant re-dispatch for all price-policy scenarios is provided in Confidential Exhibit RMP___(RTL-4).

Confidential Figure 3. Change in Annual Generation from Wyoming Coal Plants Due to Repowering

[redacted]

ANNUAL REVENUE REQUIREMENT PRICE-POLICY RESULTS

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

A. Table 3 summarizes the 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-5).

Table 3. Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($41)
Low Gas, Medium CO_2	($245)
Low Gas, High CO_2	($344)
Medium Gas, Zero CO_2	($362)
Medium Gas, Medium CO_2	($359)
Medium Gas, High CO_2	($401)
High Gas, Zero CO_2	($400)
High Gas, Medium CO_2	($274)
High Gas, High CO_2	($589)

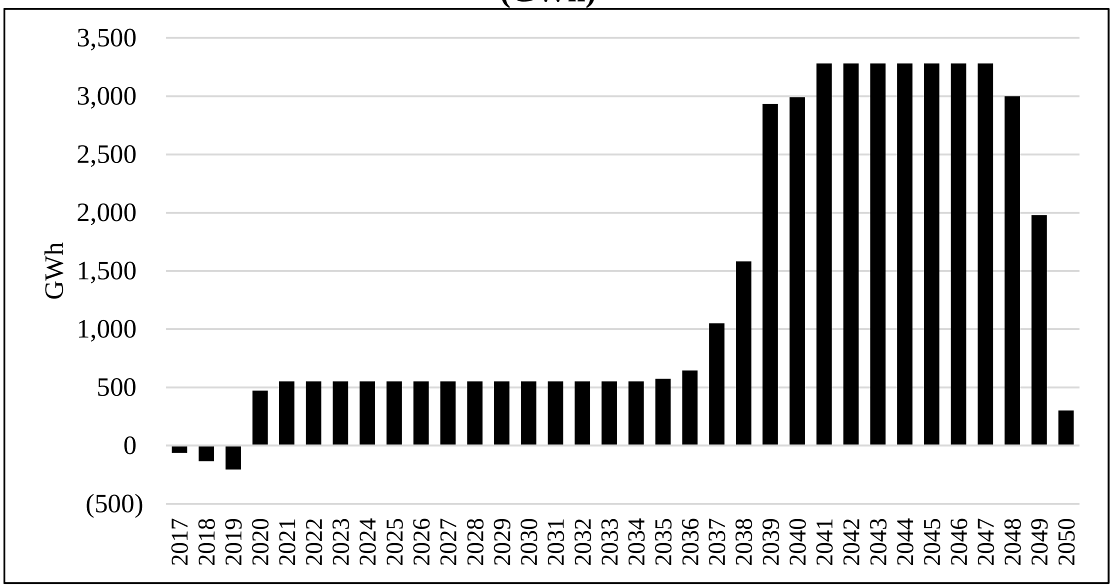
When calculated through 2050, which covers the remaining life of the repowered facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios, with PVRR(d) benefits ranging from $41 million in the low-natural-gas-and-zero-CO_2 scenario to $589 million in the high-natural-gas-and-high-CO_2 scenario. Under the central price-policy scenario, assuming medium natural gas prices and medium CO_2 prices, the PVRR(d) benefits are $359 million.

Q. What causes the substantial increase in PVRR(d) benefits when calculated off of nominal revenue requirement through 2050 relative to the PVRR(d) results calculated from the SO model and PaR results through 2036?

A. The PVRR(d) calculated from estimated annual revenue requirement through 2050 picks up the sizable increase in incremental wind energy output beyond the 20-year forecast period analyzed with the SO model and PaR. As discussed earlier in my testimony, the change in wind energy output between cases with and without wind repowering experiences a step change beyond this 20-year period, when the existing wind facilities would otherwise have hit the end of their depreciable life. Beyond the 20-year forecast period, the change in wind energy output between cases with and without repowering reflects the full energy output from the repowered wind facilities.

Figure 4 shows the incremental change in wind energy output resulting from the repowering project. Incremental energy output associated with wind repowering progressively increases over the 2036-through-2040 period, as wind facilities originally placed in service in the 2006-through-2010 time frame would have otherwise hit the end of their lives. Before 2036, and once all of the wind resources within the project scope are repowered, the average annual incremental increase in wind energy output is approximately 551 GWh. Beyond 2040, and before the new equipment hits the end of its depreciable life, the average annual incremental increase in wind-energy output is approximately 3,283 GWh.

Figure 4. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh)



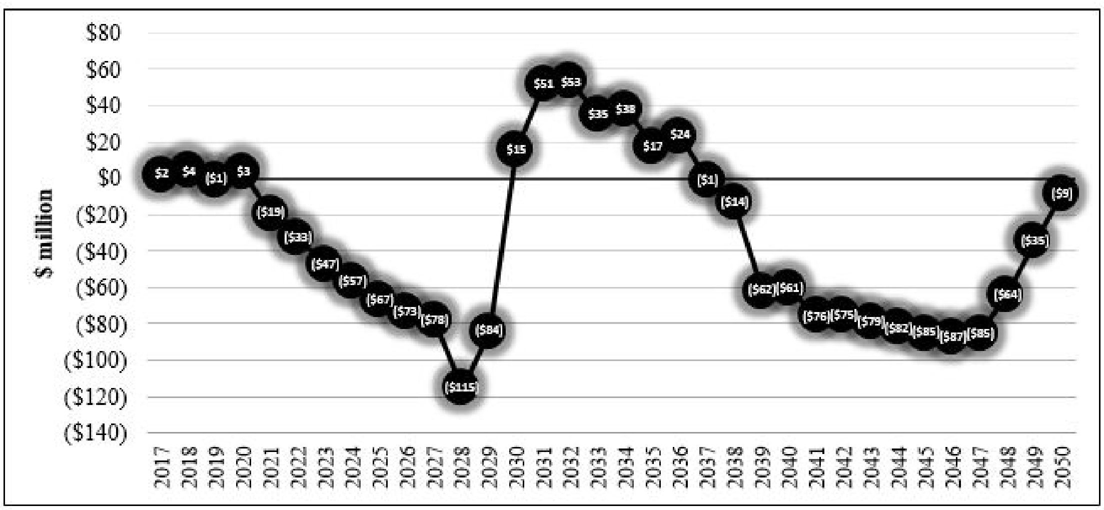
Q. Is there incremental customer upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?

A. Yes. As in the case with the PVRR(d) results calculated from the SO model and PaR results through 2036, the PVRR(d) results presented in Table 3 do not reflect the potential value of RECs produced by the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $11 million for every dollar assigned to the incremental RECs that will be generated from the wind repowering project through 2050.

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

A. Figure 5 shows the estimated change in nominal revenue requirement due to wind repowering for the medium-natural-gas-and-medium-CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects 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 system impacts of 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. Total-System Annual Revenue Requirement with Wind Repowering ($ million)



Before repowering, the reduction in wind energy output due to component failures on the existing wind resource equipment is assumed to reduce wind energy output for specific wind turbines until the time new equipment is installed. This contributes to a slight increase in revenue requirement in 2017 and 2018 ($2 million to $4 million, total system). All but the Dunlap facility, which is repowered toward the end of 2020, are repowered in 2019. Over the 2019-to-2020 time frame, project costs reflecting partial-year capital revenue requirement net of PTCs and system cost impacts, cause slight changes to revenue requirement.

The wind repowering project reduces revenue requirement soon after the new equipment is placed in service in the 2019-to-2020 time frame. From 2021 through 2028, annual revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. On a total-system basis, annual revenue requirement is reduced by $19 million in 2021. The reduction in annual revenue requirement increases to $115 million by 2028. Revenue requirement increases once the PTCs expire toward the end of 2030. Annual revenue requirement is reduced over the 2037-through-2050 time frame when, as discussed earlier in my testimony, the incremental wind energy output associated with wind repowering increases substantially.

SENSITIVITY STUDY RESULTS

Q. Please summarize the results of the sensitivity that assumes the new wind equipment has a 40-year-depreciable life.

A. Table 4 summarizes the PVRR(d) results for the sensitivity assuming a 40-year life for new equipment. To assess the relative impact of the 40-year life, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which wind repowering was evaluated with a 30-year life. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 4. 40-Year-Life Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($60)	($22)	($38)
PaR Stochastic-Mean	($50)	($13)	($37)
PaR Risk-Adjusted	($52)	($15)	($37)

If the new equipment were depreciated over a 40-year life, reduced book depreciation would drive lower annual revenue requirement. In this sensitivity, PVRR(d) benefits increase by approximately $37 million relative to the benchmark case assuming a 30-year life for the new equipment.

Q. Please summarize the results of the sensitivity that includes new incremental wind and the planned Aeolus-to-Bridger/Anticline transmission project.

A. Table 5 summarizes the PVRR(d) results for the sensitivity assuming wind repowering is implemented along with 1,180 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project. To assess the relative impact of the new wind and transmission, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which wind repowering was evaluated as a stand-alone project. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 5. New Wind and Aeolus-to-Bridger/Anticline Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($114)	($22)	($91)
PaR Stochastic-Mean	($104)	($13)	($90)
PaR Risk-Adjusted	($116)	($15)	($101)

When the wind repowering project is combined with 1,180 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project, PVRR(d) benefits increase by between $91 million to $101 million relative to the benchmark case. This sensitivity shows that wind repowering benefits persist when combined with new wind and new transmission, and that the new wind and new transmission will provide significant incremental benefits for customers.

Q. Please summarize the results of the sensitivity that assumes repowered wind facilities can operate at their full capacity.

A. Table 6 summarizes the PVRR(d) results for the sensitivity that assumes repowered wind facilities can operate at their full capacity. The increased energy and capacity assumed in this sensitivity is in addition to the new wind and transmission assumed in the prior sensitivity. To assess the relative impact of this assumption on revenue requirement, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study assuming repowered wind resources operate within existing LGIA limits. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 6. Increased Wind Repower Capacity Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($109)	($114)	$4
PaR Stochastic-Mean	($106)	($104)	($2)
PaR Risk-Adjusted	($118)	($116)	($2)

If PacifiCorp is able to modify its LGIAs, the repowered wind facilities will be able to produce additional energy in those hours where wind energy output would otherwise have been curtailed to stay within current LGIA limits. If these LGIAs are modified, PVRR(d) this study suggests there may be additional upside to customer benefits, but they are not likely to be substantial.

CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis supports repowering approximately 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional ten years of federal PTCs, produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs. The economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, NPC benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

Q. What do you recommend?

A. As supported by my economic analysis, I recommend that the Commission determine that the decision to repower certain wind facilities is prudent and in the public interest and approve the Application as filed, including the request for continued cost recovery of the wind equipment that will be replaced and the proposed ratemaking treatment for the new costs and benefits of the wind repowering project.

Q. Does this conclude your direct testimony?

A. Yes.

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

Wind Facility Data

June 2017

CONFIDENTIAL -- SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES R746-1-602 and 603

Wind Facility Data

Existing Wind Before 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	12/31/2018	12/31/2038	n/a
Glenrock 3	39.0	39.0	113,438	33.2%	n/a	12/31/2018	12/31/2038	n/a
Seven Mile Hill 1	99.0	99.0	339,195	39.1%	n/a	12/31/2018	12/31/2038	n/a
Seven Mile Hill 2	19.5	19.5	71,224	41.7%	n/a	12/31/2018	12/31/2038	n/a
High Plains	99.0	99.0	306,145	35.3%	n/a	9/30/2019	12/31/2038	n/a
McFadden Ridge	28.5	28.5	93,101	37.3%	n/a	9/30/2019	12/31/2038	n/a
Dunlap Ranch	111.0	111.0	389,045	40.0%	n/a	10/1/2020	10/1/2040	n/a
Rolling Hills	99.0	99.0	271,635	31.3%	n/a	12/31/2018	12/31/2038	n/a
Leaning Juniper	100.5	100.5	233,592	26.5%	n/a	9/14/2016	9/14/2036	n/a
Marengo 1	140.4	140.4	360,279	29.3%	n/a	8/1/2017	8/1/2037	n/a
Marengo 2	70.2	70.2	166,742	27.1%	n/a	6/1/2018	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	340,930	39.3%	[redacted]	9/30/2029	10/1/2049	10/1/2019
Glenrock 3	42.2	39.0	126,291	37.0%		9/30/2029	10/1/2049	10/1/2019
Seven Mile Hill 1	108.6	99.0	389,364	44.9%		6/30/2029	7/1/2049	7/1/2019
Seven Mile Hill 2	21.4	19.5	81,576	47.8%		6/30/2029	7/1/2049	7/1/2019
High Plains	108.6	99.0	353,449	40.8%		10/31/2029	11/1/2049	11/1/2019
McFadden Ridge	31.3	28.5	107,670	43.1%		10/31/2029	11/1/2049	11/1/2019
Dunlap Ranch	121.7	111.0	438,289	45.1%		11/30/2030	12/1/2050	12/1/2020
Rolling Hills	106.8	99.0	300,755	34.7%		9/30/2029	10/1/2049	10/1/2019
Leaning Juniper	120.6	100.5	307,906	35.0%		9/30/2029	10/1/2049	10/1/2019
Marengo 1	156.0	140.4	485,842	39.5%		10/31/2029	11/1/2049	11/1/2019
Marengo 2	78.0	70.2	224,456	36.5%		10/31/2029	11/1/2049	11/1/2019
Goodnoe Hills	94.0	94.0	263,089	31.9%		9/30/2029	10/1/2049	10/1/2019
Total	1,096.8	999.1	3,419,617	35.6%	$1,128			

Increase/(Decrease) in Run-Rate Operating Costs Due to Repowering ($m)

Run-Rate Capital

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
All Repowered Projects	($9.8)	($14.7)	($18.6)	($19.0)	($18.4)	($15.5)	($14.3)	($10.3)	($7.5)	($5.0)	($3.6)	($3.7)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	($2.2)	($2.9)	($2.3)	($1.8)	($1.8)	($1.8)	($1.9)	($1.0)	$1.1	$9.1	$16.1	$17.0

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$18.8	$19.2	$19.6	$20.1	$20.5	$21.0	$21.5	$22.0	$12.9	$1.7

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	$0.6	$4.4	$3.9	$0.8	$0.9	$0.9	$0.9	$0.9	$0.9	$1.0

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	$1.0	$1.0	$1.0	$1.0	$1.1	$1.1	$1.1	$1.9	$5.4	$13.5	$28.0	$29.4

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$32.2	$32.9	$33.7	$34.4	$35.2	$36.0	$36.9	$37.7	$29.8	$2.6

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

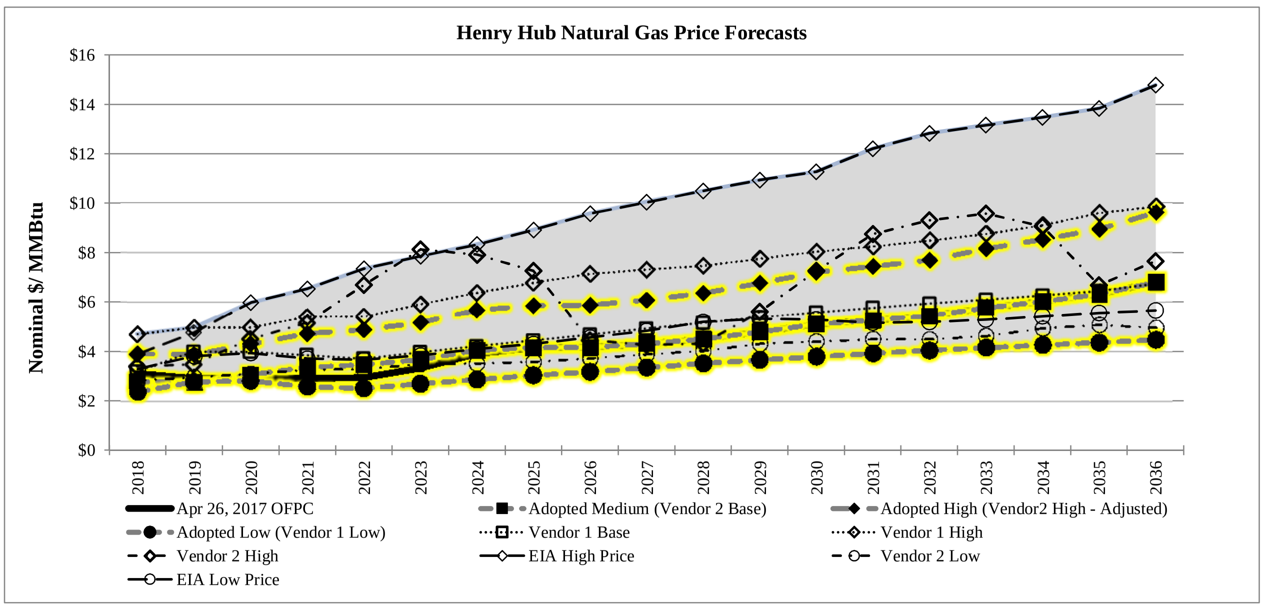
Exhibit Accompanying Direct Testimony of Rick T. Link

Nominal Henry Hub Natural Gas Price Forecasts ($/MMBtu)

June 2017

Nominal Henry Hub Natural Gas Price Forecasts ($/MMBtu)

Year	Apr 26, 2017 OFPC	Adopted Medium (Vendor 2 Base)	Adopted High (Vendor2 High - Adjusted)	Adopted Low (Vendor 1 Low)	Vendor 1 Base	Vendor 1 High	Vendor 2 High	EIA Low Price	EIA High Price	Vendor 2 Low	Lowest Price	Highest Price	Range
2018	$3.14	$2.80	$3.92	$2.39	$3.21	$4.71	$3.41	$3.29	$3.89	$2.85	$2.39	$4.71	$2.32
2019	$2.92	$2.77	$3.89	$2.79	$4.00	$4.97	$3.49	$3.82	$4.77	$2.98	$2.77	$4.97	$2.20
2020	$2.92	$3.08	$4.32	$2.83	$3.99	$4.98	$4.51	$3.94	$5.98	$3.12	$2.83	$5.98	$3.15
2021	$2.94	$3.38	$4.74	$2.60	$3.86	$5.41	$5.16	$3.71	$6.54	$3.28	$2.60	$6.54	$3.94
2022	$2.97	$3.48	$4.89	$2.54	$3.72	$5.43	$6.69	$3.66	$7.35	$3.31	$2.54	$7.35	$4.81
2023	$3.35	$3.69	$5.18	$2.72	$3.98	$5.93	$8.13	$3.84	$7.86	$3.51	$2.72	$7.86	$5.14
2024	$3.92	$4.06	$5.69	$2.89	$4.22	$6.39	$7.92	$4.10	$8.33	$3.53	$2.89	$8.33	$5.44
2025	$4.16	$4.16	$5.88	$3.05	$4.45	$6.80	$7.26	$4.31	$8.92	$3.60	$3.05	$8.92	$5.87
2026	$4.18	$4.18	$5.90	$3.20	$4.68	$7.16	$4.46	$4.57	$9.58	$3.74	$3.20	$9.58	$6.38
2027	$4.33	$4.33	$6.11	$3.37	$4.93	$7.33	$4.27	$4.84	$10.04	$3.90	$3.37	$10.04	$6.67
2028	$4.52	$4.52	$6.38	$3.54	$5.16	$7.49	$4.33	$5.20	$10.50	$4.04	$3.54	$10.50	$6.96
2029	$4.81	$4.81	$6.79	$3.68	$5.39	$7.77	$5.61	$5.34	$10.94	$4.32	$3.68	$10.94	$7.26
2030	$5.12	$5.12	$7.23	$3.81	$5.59	$8.05	$7.27	$5.30	$11.28	$4.42	$3.81	$11.28	$7.47
2031	$5.28	$5.28	$7.46	$3.94	$5.78	$8.26	$8.75	$5.17	$12.21	$4.51	$3.94	$12.21	$8.27
2032	$5.46	$5.46	$7.71	$4.06	$5.95	$8.50	$9.31	$5.20	$12.83	$4.50	$4.06	$12.83	$8.77
2033	$5.79	$5.79	$8.17	$4.17	$6.11	$8.77	$9.58	$5.30	$13.16	$4.64	$4.17	$13.16	$8.99
2034	$6.05	$6.05	$8.54	$4.27	$6.28	$9.11	$9.07	$5.43	$13.48	$4.94	$4.27	$13.48	$9.21
2035	$6.34	$6.34	$8.95	$4.37	$6.46	$9.61	$6.68	$5.56	$13.84	$5.08	$4.37	$13.84	$9.47
2036	$6.82	$6.82	$9.63	$4.48	$6.76	$9.86	$7.66	$5.66	$14.78	$4.97	$4.48	$14.78	$10.30



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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

SO Model Annual Results ($ million)

June 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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($107)	$1	$3	$2	($9)	($11)	($11)	($12)	($12)	($13)	($13)	($14)	($17)	($18)	$8	($3)	($25)	($29)	($24)	($22)	($21)
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)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($1)	($1)	($1)	$0	$0	$0	$0	$0
Change in System Fixed Cost	$17	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$4	$4	($35)	$15	$28	$20	$12	$3	$1
Net (Benefit)/Cost	$33	$12	$13	$12	$1	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($2)	($2)	($14)	$25	$17	$6	$3	($3)	($4)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($230)	$1	$2	$1	($11)	($13)	($14)	($14)	($15)	($15)	($16)	($14)	($18)	($42)	($52)	($50)	($53)	($59)	($61)	($64)	($67)
Change in Emissions	$14	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($0)	($1)	($0)	($1)	$5	$5	$6	$7	$7	$9	$9
Change in DSM	$11	$0	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$0	$0	($0)	($2)	($2)
Change in System Fixed Cost	$71	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($3)	$37	$28	$19	$16	$25	$25	$25	$27
Net (Benefit)/Cost	($0)	$12	$13	$13	$1	($1)	($1)	($1)	($1)	($2)	($3)	$0	($7)	$9	($4)	($12)	($16)	($12)	($14)	($17)	($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
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($126)	$1	$3	$2	($11)	($13)	($13)	($13)	($13)	($15)	($16)	($15)	($17)	($17)	($19)	($19)	($20)	($21)	($22)	($23)	($24)
Change in Emissions	($26)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($1)	($4)	($5)	($7)	($6)	($7)	($8)	($8)	($8)	($8)	($7)
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	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($18)	$12	$13	$12	$0	($1)	($1)	($2)	($1)	($3)	($4)	($6)	($9)	($10)	($11)	($12)	($14)	($14)	($15)	($15)	($15)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($186)	$2	$3	$2	($10)	($13)	($14)	($15)	($16)	($17)	($17)	($17)	($59)	($35)	($20)	($24)	($60)	($28)	($29)	($30)	($32)
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	($0)	($1)	($1)	($1)	($0)	($0)	$0	($0)	($0)	($0)	($2)	($2)
Change in System Fixed Cost	$21	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$60	($32)	($23)	($19)	$63	$1	$1	$1	$2
Net (Benefit)/Cost	($33)	$12	$13	$12	$1	($1)	($2)	($3)	($4)	($5)	($5)	($5)	$13	($54)	($29)	($29)	$18	($13)	($14)	($15)	($16)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($293)	$1	$3	$1	($12)	($15)	($19)	($21)	($23)	($24)	($25)	($26)	($30)	($31)	($48)	($82)	($109)	($66)	($70)	($22)	($99)
Change in Emissions	($15)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($2)	($1)	($5)	($9)	($10)	($2)	($1)	($0)	($4)
Change in DSM	$63	$0	$1	$2	$2	$2	$3	$5	$5	$7	$7	$8	$8	$11	$12	$13	$13	$13	$13	$13	$13
Change in System Fixed Cost	$89	$0	($0)	($0)	$0	$0	$4	$4	$4	$4	$4	$4	($15)	($16)	$8	$56	$90	$31	$31	($23)	$60
Net (Benefit)/Cost	($22)	$12	$14	$13	$1	($2)	($1)	($1)	($1)	($3)	($2)	($3)	($25)	($24)	($19)	($8)	($2)	($9)	($11)	($17)	($14)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($151)	$1	$3	$2	($11)	($14)	($15)	($16)	($17)	($18)	($17)	($18)	($21)	($21)	($22)	($23)	($24)	($25)	($27)	($28)	($30)
Change in Emissions	($24)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($4)	($5)	($6)	($6)	($7)	($7)	($7)	($8)	($7)
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	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($41)	$12	$13	$12	($0)	($3)	($3)	($4)	($5)	($6)	($7)	($9)	($12)	($13)	($14)	($15)	($16)	($18)	($19)	($21)	($22)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($277)	$2	$4	$2	($14)	($19)	($21)	($22)	($24)	($25)	($25)	($26)	($29)	($29)	($31)	($18)	($33)	($89)	($82)	($133)	($81)
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	$31	$0	($0)	($0)	($0)	$1	$2	$2	$2	$3	$3	$3	$3	$4	$5	$6	$6	$8	$9	$10	$10
Change in System Fixed Cost	$36	$0	($0)	($0)	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($5)	($6)	($19)	($7)	$9	($4)	$71	$99
Net (Benefit)/Cost	($75)	$12	$14	$13	($4)	($7)	($7)	($8)	($9)	($10)	($10)	($10)	($13)	($16)	($18)	($18)	($19)	($57)	($62)	($37)	$44

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($179)	$2	$4	$3	($14)	($17)	($17)	($18)	($19)	($19)	($20)	($20)	($34)	($28)	($30)	($32)	($55)	($7)	($10)	($73)	$8
Change in Emissions	$4	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($0)	($1)	$4	$5	$5	$8
Change in DSM	($70)	$0	$0	($1)	($2)	($3)	($4)	($4)	($5)	($6)	($6)	($7)	($9)	($9)	($12)	($14)	($15)	($17)	($18)	($19)	($22)
Change in System Fixed Cost	$46	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$14	$7	$10	$12	$40	$10	$15	$38	($22)
Net (Benefit)/Cost	($64)	$12	$14	$12	($5)	($9)	($9)	($10)	($12)	($14)	($14)	($15)	($16)	($17)	($19)	($20)	($16)	$6	$6	($35)	($13)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($199)	$2	$4	$2	($15)	($19)	($20)	($21)	($23)	($24)	($24)	($25)	($13)	($30)	($36)	($38)	($30)	($38)	($40)	($41)	($12)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	$0	($4)	($3)	($2)	($5)	($5)	($4)	($5)	($21)
Change in DSM	$9	$0	$0	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Change in System Fixed Cost	($28)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($18)	$0	$4	$4	($2)	$2	$2	$2	($87)
Net (Benefit)/Cost	($103)	$12	$14	$13	($3)	($7)	($7)	($8)	($10)	($11)	($12)	($14)	($17)	($19)	($20)	($21)	($21)	($25)	($26)	($28)	($103)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($82)	$1	$2	$0	($6)	($9)	($10)	($10)	($12)	($11)	($9)	($10)	($12)	($15)	$13	$6	($13)	($27)	($22)	($22)	($21)
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	($12)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($0)	($9)	($9)	($9)	($0)	($0)	($0)	($0)
Change in DSM	($13)	$0	($0)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($1)	($1)	($1)	$0	$0	$0	($0)	($0)
Change in Deficiency	($1)	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$1	$1	($1)	($2)	$0	($1)
Change in System Fixed Cost	$17	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$4	$4	($35)	$15	$28	$20	$12	$3	$1
Net (Benefit)/Cost	$43	$11	$12	$10	$4	$1	$0	($1)	($2)	($1)	$1	($0)	$2	$1	($17)	$25	$21	$6	$2	($3)	($5)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($222)	$1	$2	($1)	($9)	($12)	($13)	($13)	($16)	($15)	($13)	($12)	($15)	($45)	($53)	($51)	($49)	($56)	($58)	($62)	($64)
Change in Emissions	$5	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($2)	($6)	$2	$3	$4	$5	$5	$6	$6
Change in VOM	$9	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$8	$3	$3	$3	$3	$3	$2	$2
Change in DSM	$12	$0	$1	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$0	$0	$0	($2)	($2)
Change in Deficiency	($0)	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$1	$1	($0)	$0	($1)	$1	($2)
Change in System Fixed Cost	$71	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($3)	$37	$28	$19	$16	$25	$25	$25	$27
Net (Benefit)/Cost	$9	$11	$13	$11	$3	$1	$0	$0	($2)	($2)	$0	$1	($5)	$9	($4)	($9)	($12)	($8)	($12)	($14)	($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
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($123)	$1	$2	$0	($9)	($11)	($12)	($12)	($15)	($14)	($12)	($14)	($17)	($19)	($20)	($19)	($17)	($22)	($20)	($25)	($22)
Change in Emissions	($24)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($4)	($10)	($5)	($6)	($3)	($7)	($2)	($8)
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	($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	($1)	($0)	($1)	($3)	($2)	($0)
Change in System Fixed Cost	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($17)	$11	$12	$11	$2	($0)	($1)	($1)	($3)	($3)	($3)	($5)	($10)	($10)	($16)	($11)	($9)	($12)	($15)	($14)	($15)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($176)	$1	$2	($0)	($8)	($11)	($13)	($14)	($17)	($16)	($13)	($15)	($61)	($32)	($23)	($24)	($51)	($25)	($25)	($28)	($28)
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)	$4	($4)	($1)	($0)	($1)	($0)	($0)	($0)	($0)
Change in DSM	($2)	$0	($0)	($0)	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	($0)	($2)	($2)
Change in Deficiency	$1	$0	$0	$0	($0)	$0	$0	$0	($0)	($0)	$0	$0	$0	$1	$1	$1	$0	($2)	$2	($1)	$1
Change in System Fixed Cost	$21	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$60	($32)	($23)	($19)	$63	$1	$1	$1	$2
Net (Benefit)/Cost	($24)	$11	$12	$10	$3	$0	($1)	($2)	($5)	($4)	($1)	($3)	$14	($54)	($32)	($28)	$25	($13)	($8)	($15)	($12)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($273)	$1	$2	($1)	($10)	($14)	($18)	($19)	($24)	($23)	($21)	($24)	($29)	($31)	($46)	($74)	($97)	($65)	($65)	($24)	($82)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($1)	($2)	($2)	($2)	($5)	($7)	($9)	($3)	($4)	($0)	($10)
Change in VOM	($14)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($9)	($9)	($10)	($1)	($1)	($0)	($3)
Change in DSM	$68	$0	$1	$2	$2	$2	$3	$5	$6	$7	$7	$8	$9	$11	$13	$14	$14	$14	$14	$14	$14
Change in Deficiency	$0	$0	$0	$0	$0	($0)	$0	($0)	$0	$0	$0	($0)	$0	$1	$1	$1	($0)	($2)	($1)	$0	($1)
Change in System Fixed Cost	$89	$0	($0)	($0)	$0	$0	$4	$4	$4	$4	$4	$4	($15)	($16)	$8	$56	$90	$31	$31	($23)	$60
Net (Benefit)/Cost	($13)	$10	$13	$11	$3	($0)	$1	$1	($2)	($1)	$2	$0	($24)	($23)	($24)	($6)	$1	($10)	($10)	($18)	($5)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($142)	$1	$2	$0	($9)	($13)	($14)	($14)	($18)	($16)	($14)	($16)	($18)	($23)	($23)	($22)	($21)	($24)	($23)	($29)	($27)
Change in Emissions	($23)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($2)	($10)	($5)	($6)	($5)	($8)	($4)	($5)
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	($2)	($0)	$0	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	($0)	$0	$0	($0)	($0)	($2)	($1)	($1)	($1)
Change in System Fixed Cost	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($35)	$11	$12	$11	$2	($1)	($2)	($3)	($6)	($5)	($4)	($7)	($11)	($12)	($19)	($13)	($12)	($17)	($17)	($19)	($19)

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($236)	$1	$2	$0	($11)	($16)	($19)	($19)	($23)	($22)	($19)	($22)	($22)	($27)	($32)	($15)	($27)	($74)	($64)	($111)	($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 VOM	($6)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($5)	($5)	($6)	($1)
Change in DSM	$33	$0	($0)	($0)	($0)	$1	$2	$3	$2	$3	$3	$3	$4	$5	$5	$6	$7	$8	$10	$11	$11
Change in Deficiency	($1)	($0)	($0)	($0)	$0	$0	($0)	$0	($0)	$0	($0)	($0)	$0	($0)	$0	$1	$0	($2)	$2	($1)	($3)
Change in System Fixed Cost	$36	$0	($0)	($0)	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($5)	($6)	($19)	($7)	$9	($4)	$71	$99
Net (Benefit)/Cost	($40)	$11	$13	$10	($1)	($4)	($5)	($5)	($9)	($6)	($4)	($6)	($6)	($14)	($18)	($14)	($13)	($49)	($47)	($21)	$59

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($154)	$1	$2	$0	($11)	($14)	($16)	($16)	($19)	($17)	($14)	($16)	($31)	($25)	($32)	($27)	($44)	($8)	($8)	($55)	$18
Change in Emissions	$5	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($1)	$6	$5	$3	$10
Change in VOM	$6	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$5	$5	$4	$6
Change in DSM	($74)	$0	$0	($1)	($2)	($4)	($4)	($4)	($5)	($7)	($7)	($8)	($9)	($10)	($12)	($14)	($16)	($18)	($19)	($20)	($23)
Change in Deficiency	$3	($0)	($0)	($0)	$0	$0	($0)	($0)	($0)	$0	($0)	($0)	($0)	$0	$0	$1	$0	$1	$2	$6	$3
Change in System Fixed Cost	$46	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$14	$7	$10	$12	$40	$10	$15	$38	($22)
Net (Benefit)/Cost	($34)	$11	$13	$10	($2)	($6)	($8)	($8)	($13)	($12)	($9)	($12)	($14)	($15)	($21)	($16)	($6)	$11	$16	($9)	$7

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	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($175)	$1	$2	$0	($12)	($16)	($18)	($18)	($22)	($21)	($18)	($20)	($13)	($26)	($37)	($30)	($24)	($29)	($31)	($32)	($21)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($0)	($6)	($6)	($5)	($3)	($3)	($5)	($6)	($7)
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($3)
Change in DSM	$9	$0	$0	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Change in Deficiency	($1)	$0	($0)	($0)	$0	$0	($0)	$0	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($2)	$0	$1	$1
Change in System Fixed Cost	($28)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($18)	$0	$4	$4	($2)	$2	$2	$2	($87)
Net (Benefit)/Cost	($80)	$11	$13	$11	$0	($4)	($6)	($5)	($10)	($9)	($7)	($10)	($16)	($18)	($24)	($16)	($15)	($17)	($17)	($19)	($100)

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-4)
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 Direct Testimony of Rick T. Link

PaR Stochastic Mean Wyoming Coal Generation (GWh)

June 2017

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

Rocky Mountain Power
Exhibit RMP___(RTL-5)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results ($ million)

June 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	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$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
NPC	($260)	$1	$2	$0	($6)	($9)	($10)	($10)	($12)	($11)	($9)	($10)	($12)	($15)	$13	$6	($13)	($27)	($22)	($22)	($21)	($25)	($39)	($73)	($76)	($86)	($87)	($89)	($91)	($93)	($95)	($98)	($91)	($61)	($10)
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	($89)	$0	($0)	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($1)	($10)	($10)	($9)	($1)	($2)	$0	($1)	($9)	($14)	($26)	($27)	($30)	($31)	($32)	($33)	($33)	($34)	($35)	($32)	($22)	($3)
System Fixed Costs	$108	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$4	$4	($35)	$15	$28	$20	$12	$3	$1	$13	$20	$38	$39	$44	$45	$46	$47	$48	$49	$50	$47	$32	$5
Net System Impacts	($241)	$1	$2	($0)	($7)	($11)	($11)	($12)	($15)	($13)	($11)	($13)	($11)	($13)	($31)	$11	$6	($8)	($13)	($18)	($21)	($21)	($32)	($62)	($64)	($72)	($74)	($75)	($77)	($79)	($80)	($82)	($77)	($52)	($8)
Net (Benefit)/Cost	($41)	$2	$3	($2)	$4	($18)	($34)	($49)	($57)	($67)	($74)	($79)	($90)	($60)	$22	$82	$72	$52	$50	$32	$24	$36	$43	$46	$52	$50	$54	$53	$52	$53	$53	$58	$70	$56	$5

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	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$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
NPC	($935)	$1	$2	($1)	($9)	($12)	($13)	($13)	($16)	($15)	($13)	($12)	($15)	($45)	($53)	($51)	($49)	($56)	($58)	($62)	($64)	($100)	($155)	($293)	($305)	($343)	($350)	($358)	($366)	($374)	($382)	($391)	($365)	($246)	($38)
Emissions	$38	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($2)	($6)	$2	$3	$4	$5	$5	$6	$6	$4	$7	$13	$13	$15	$15	$16	$16	$16	$17	$17	$16	$11	$2
Other Variable Costs	$71	$0	$1	$1	$2	$2	$1	$2	$2	$2	$2	$2	$1	$9	$6	$6	$3	$3	$1	$1	($2)	$7	$11	$20	$21	$24	$24	$25	$26	$26	$27	$27	$25	$17	$3
System Fixed Costs	$383	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($3)	$37	$28	$19	$16	$25	$25	$25	$27	$44	$68	$128	$134	$150	$153	$157	$160	$164	$168	$171	$160	$108	$17
Net System Impacts	($445)	$1	$2	$1	($8)	($11)	($12)	($12)	($14)	($14)	($12)	($12)	($18)	($5)	($18)	($23)	($26)	($23)	($27)	($30)	($34)	($45)	($69)	($131)	($137)	($154)	($157)	($161)	($164)	($168)	($171)	($175)	($164)	($110)	($17)
Net (Benefit)/Cost	($245)	$2	$4	($1)	$4	($18)	($34)	($48)	($57)	($68)	($75)	($77)	($96)	($52)	$35	$48	$40	$37	$36	$21	$11	$12	$7	($24)	($21)	($31)	($30)	($32)	($35)	($36)	($38)	($35)	($17)	($3)	($4)

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	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$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
NPC	($414)	$1	$2	$0	($9)	($11)	($12)	($12)	($15)	($14)	($12)	($14)	($17)	($19)	($20)	($19)	($17)	($22)	($20)	($25)	($22)	($41)	($63)	($119)	($125)	($140)	($143)	($146)	($149)	($153)	($156)	($159)	($149)	($100)	($16)
Emissions	($116)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($4)	($10)	($5)	($6)	($3)	($7)	($2)	($8)	($12)	($18)	($35)	($36)	($41)	($42)	($43)	($44)	($45)	($46)	($47)	($44)	($29)	($5)
Other Variable Costs	($21)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	$0	($2)	($1)	($2)	($4)	($2)	($1)	($2)	($4)	($7)	($7)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($8)	($6)	($1)
System Fixed Costs	($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)
Net System Impacts	($544)	$1	$2	$0	($9)	($11)	($12)	($12)	($15)	($16)	($15)	($18)	($23)	($23)	($30)	($25)	($24)	($27)	($30)	($30)	($31)	($55)	($85)	($161)	($168)	($189)	($193)	($197)	($201)	($206)	($210)	($215)	($201)	($136)	($21)
Net (Benefit)/Cost	($344)	$2	$3	($1)	$3	($19)	($34)	($49)	($58)	($69)	($77)	($84)	($102)	($71)	$23	$46	$42	$33	$33	$21	$13	$2	($9)	($53)	($52)	($66)	($65)	($69)	($72)	($74)	($77)	($75)	($54)	($28)	($8)

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	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$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
NPC	($689)	$1	$2	($0)	($8)	($11)	($13)	($14)	($17)	($16)	($13)	($15)	($61)	($32)	($23)	($24)	($51)	($25)	($25)	($28)	($28)	($72)	($111)	($210)	($219)	($246)	($251)	($257)	($263)	($269)	($275)	($281)	($262)	($177)	($28)
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	($0)	($1)	($1)	$3	($4)	$0	$1	($1)	($2)	$1	($4)	($2)	($1)	($2)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($5)	($4)	($1)
System Fixed Costs	$140	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$60	($32)	($23)	($19)	$63	$1	$1	$1	$2	$17	$26	$49	$51	$57	$58	$59	$61	$62	$63	$65	$61	$41	$6
Net System Impacts	($562)	$1	$2	($0)	($8)	($11)	($13)	($14)	($17)	($16)	($14)	($16)	$1	($67)	($46)	($42)	$10	($27)	($23)	($30)	($28)	($57)	($88)	($166)	($173)	($194)	($198)	($203)	($207)	($212)	($217)	($221)	($207)	($139)	($22)
Net (Benefit)/Cost	($362)	$2	$3	($2)	$3	($19)	($35)	($50)	($60)	($70)	($76)	($81)	($77)	($115)	$7	$29	$76	$33	$40	$20	$16	$0	($12)	($58)	($57)	($72)	($71)	($75)	($78)	($81)	($83)	($81)	($60)	($32)	($8)

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	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$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
NPC	($1,101)	$1	$2	($1)	($10)	($14)	($18)	($19)	($24)	($23)	($21)	($24)	($29)	($31)	($46)	($74)	($97)	($65)	($65)	($24)	($82)	($116)	($179)	($340)	($354)	($398)	($406)	($415)	($425)	($434)	($444)	($454)	($423)	($286)	($44)
Emissions	($89)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($1)	($2)	($2)	($2)	($5)	($7)	($9)	($3)	($4)	($0)	($10)	($9)	($14)	($27)	($28)	($32)	($33)	($33)	($34)	($35)	($36)	($36)	($34)	($23)	($4)
Other Variable Costs	$186	$0	$1	$2	$2	$2	$3	$5	$6	$7	$7	$8	$9	$11	$4	$6	$4	$12	$12	$14	$11	$19	$29	$54	$56	$63	$65	$66	$68	$69	$71	$72	$67	$45	$7
System Fixed Costs	$439	$0	($0)	($0)	$0	$0	$4	$4	$4	$4	$4	$4	($15)	($16)	$8	$56	$90	$31	$31	($23)	$60	$49	$76	$144	$150	$168	$172	$176	$180	$184	$188	$192	$179	$121	$19
Net System Impacts	($559)	$1	$2	$1	($8)	($11)	($11)	($11)	($14)	($14)	($11)	($13)	($37)	($37)	($38)	($20)	($13)	($25)	($25)	($33)	($21)	($58)	($89)	($169)	($177)	($198)	($203)	($207)	($212)	($216)	($221)	($226)	($211)	($142)	($22)
Net (Benefit)/Cost	($359)	$2	$4	($1)	$3	($19)	($33)	($47)	($57)	($67)	($73)	($78)	($115)	($84)	$15	$51	$53	$35	$38	$17	$24	($1)	($14)	($62)	($61)	($76)	($75)	($79)	($82)	($85)	($87)	($85)	($64)	($35)	($9)

Rocky Mountain Power
Exhibit RMP___(RTL-5) Page 2 of 2
Docket No. 17-035-39
Witness: Rick T. Link

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
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($480)	$1	$2	$0	($9)	($13)	($14)	($14)	($18)	($16)	($14)	($16)	($18)	($23)	($23)	($22)	($21)	($24)
Emissions	($114)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($2)	($10)	($5)	($6)	($5)
Other Variable Costs	($15)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($1)	($2)
System Fixed Costs	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	$0
Net System Impacts	($602)	$1	$2	$0	($9)	($13)	($14)	($15)	($18)	($18)	($16)	($20)	($24)	($26)	($33)	($28)	($27)	($32)
Net (Benefit)/Cost	($401)	$2	$3	($1)	$2	($20)	($36)	($51)	($61)	($71)	($79)	($86)	($103)	($73)	$20	$44	$39	$29

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($23)	($29)	($27)	($47)	($73)	($139)	($144)	($162)	($166)	($169)	($173)	($177)	($181)	($185)	($173)	($116)	($18)
Emissions	($8)	($4)	($5)	($12)	($18)	($34)	($36)	($40)	($41)	($42)	($43)	($44)	($45)	($46)	($43)	($29)	($5)
Other Variable Costs	($1)	($1)	($2)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($4)	($1)
System Fixed Costs	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Net System Impacts	($32)	($34)	($34)	($61)	($94)	($178)	($185)	($208)	($213)	($217)	($222)	($227)	($232)	($237)	($222)	($150)	($23)
Net (Benefit)/Cost	$31	$16	$10	($4)	($18)	($70)	($70)	($86)	($85)	($89)	($93)	($96)	($99)	($97)	($75)	($42)	($10)

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
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($895)	$1	$2	$0	($11)	($16)	($19)	($19)	($23)	($22)	($19)	($22)	($22)	($27)	($32)	($15)	($27)	($74)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	$99	($0)	($0)	($0)	($0)	$1	$2	$3	$2	$3	$3	$3	$3	$4	$6	$7	$7	$1
System Fixed Costs	$196	$0	($0)	($0)	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($5)	($6)	($19)	($7)	$9
Net System Impacts	($600)	$1	$2	($0)	($12)	($15)	($17)	($16)	($21)	($19)	($16)	($19)	($19)	($27)	($32)	($28)	($27)	($63)
Net (Benefit)/Cost	($400)	$3	$4	($2)	($0)	($23)	($39)	($53)	($64)	($72)	($78)	($84)	($97)	($75)	$21	$44	$39	($3)

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($64)	($111)	($63)	($93)	($143)	($270)	($282)	($316)	($323)	($330)	($338)	($345)	($353)	($361)	($337)	($227)	($35)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	$7	$4	$7	$10	$16	$30	$31	$35	$36	$37	$38	$38	$39	$40	$37	$25	$4
System Fixed Costs	($4)	$71	$99	$22	$35	$66	$68	$77	$78	$80	$82	$84	$86	$87	$82	$55	$9
Net System Impacts	($62)	($37)	$43	($60)	($92)	($175)	($182)	($204)	($209)	($214)	($218)	($223)	($228)	($233)	($218)	($147)	($23)
Net (Benefit)/Cost	$1	$14	$88	($3)	($16)	($67)	($66)	($82)	($82)	($86)	($89)	($92)	($95)	($93)	($71)	($39)	($9)

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
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($517)	$1	$2	$0	($11)	($14)	($16)	($16)	($19)	($17)	($14)	($16)	($31)	($25)	($32)	($27)	($44)	($8)
Emissions	$32	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($1)	$6
Other Variable Costs	($245)	($0)	$0	($1)	($2)	($4)	($4)	($4)	($6)	($7)	($7)	($8)	($10)	($10)	($12)	($14)	($16)	($12)
System Fixed Costs	$258	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$14	$7	$10	$12	$40	$10
Net System Impacts	($474)	$1	$2	($1)	($13)	($18)	($20)	($20)	($25)	($24)	($22)	($25)	($28)	($29)	($35)	($30)	($21)	($4)
Net (Benefit)/Cost	($274)	$3	$4	($2)	($2)	($25)	($42)	($56)	($68)	($78)	($84)	($91)	($106)	($76)	$18	$42	$45	$56

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($8)	($55)	$18	($51)	($79)	($149)	($155)	($174)	($178)	($182)	($186)	($190)	($194)	($199)	($186)	($125)	($19)
Emissions	$5	$3	$10	$4	$5	$10	$11	$12	$12	$13	$13	$13	$14	$14	$13	$9	$1
Other Variable Costs	($12)	($10)	($14)	($25)	($39)	($74)	($77)	($86)	($88)	($90)	($92)	($94)	($96)	($98)	($92)	($62)	($10)
System Fixed Costs	$15	$38	($22)	$30	$46	$87	$91	$102	$104	$106	$109	$111	$113	$116	$108	$73	$11
Net System Impacts	$1	($25)	($8)	($43)	($66)	($125)	($131)	($147)	($150)	($153)	($157)	($160)	($164)	($167)	($156)	($105)	($16)
Net (Benefit)/Cost	$64	$26	$36	$14	$10	($18)	($15)	($24)	($23)	($25)	($27)	($29)	($30)	($27)	($10)	$2	($3)

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
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($565)	$1	$2	$0	($12)	($16)	($18)	($18)	($22)	($21)	($18)	($20)	($13)	($26)	($37)	($30)	($24)	($29)
Emissions	($87)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($0)	($6)	($6)	($5)	($3)	($3)
Other Variable Costs	$14	$0	$0	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	($1)
System Fixed Costs	($156)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($18)	$0	$4	$4	($2)	$2
Net System Impacts	($789)	$1	$2	$0	($11)	($15)	($17)	($17)	($22)	($21)	($19)	($23)	($30)	($31)	($38)	($30)	($29)	($31)
Net (Benefit)/Cost	($589)	$3	$4	($1)	$0	($23)	($39)	($53)	($65)	($75)	($81)	($89)	($108)	($79)	$15	$42	$37	$29

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPC	($31)	($32)	($21)	($55)	($84)	($160)	($167)	($187)	($191)	($196)	($200)	($204)	($209)	($214)	($199)	($135)	($21)
Emissions	($5)	($6)	($7)	($9)	($14)	($26)	($27)	($31)	($31)	($32)	($33)	($33)	($34)	($35)	($33)	($22)	($3)
Other Variable Costs	$1	$1	($1)	$1	$1	$3	$3	$3	$3	$3	$3	$4	$4	$4	$3	$2	$0
System Fixed Costs	$2	$2	($87)	($18)	($28)	($52)	($55)	($61)	($63)	($64)	($66)	($67)	($69)	($70)	($65)	($44)	($7)
Net System Impacts	($32)	($35)	($116)	($81)	($124)	($236)	($246)	($276)	($282)	($288)	($295)	($301)	($308)	($315)	($294)	($198)	($31)
Net (Benefit)/Cost	$31	$16	($71)	($24)	($49)	($128)	($130)	($154)	($155)	($160)	($165)	($170)	($174)	($174)	($147)	($91)	($17)

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

Direct Testimony of Jeffrey K. Larsen

June 2017

INTRODUCTION AND SUMMARY

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Rocky Mountain Power ("Company").

A. My name is Jeffrey K. Larsen, and my business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am currently employed as Vice President of Regulation for Rocky Mountain Power.

Q. Please describe your education and professional background.

A. I received a Master of Business Administration degree from Utah State University in 1994, and a Bachelor of Science degree in Accounting from Brigham Young University in 1985. I have also participated in the Company's Business Leadership Program through the Wharton School, and an Advanced Education Program through the J.L. Kellogg School of Management at Northwestern University. In addition to formal education, I have also attended various educational, professional and electric industry-related seminars and training programs during my career at the Company. I joined the Company in 1985, and I have held various accounting, compliance, regulatory, and management-related positions prior to my current position.

Q. Have you provided testimony in previous regulatory proceedings?

A. Yes. I have filed testimony on various matters in the states of Utah, Idaho, Wyoming, California, Washington, Oregon, and Nevada.

Q. What is the purpose of your testimony?

A. I explain the Company's requested ratemaking treatment for the wind repowering project for which the Company is seeking approval in this Application. Specifically, I describe how the Company proposes to match the costs and benefits of the wind repowering project by deferring the costs and benefits that do not go through the Energy Balancing Account ("EBA") and passing back the net benefits through the proposed Resource Tracking Mechanism ("RTM"). I also explain and support the Company's proposed accounting treatment and request for continued cost recovery of the upgraded and replaced wind equipment.

Q. Please summarize the Company's proposed ratemaking treatment for the wind repowering project.

A. The Company requests approval of its decision to act on the time-constrained economic opportunity to upgrade most of its wind facilities and requalify for federal production tax credits ("PTCs"). The wind repowering project will provide customers additional cost-effective generation, and tax benefits resulting from renewed PTC eligibility, and extend the life of the repowered facilities by at least an additional 10 years.

The proposed RTM is designed to capture customer benefits resulting from wind repowering, and match those benefits with the costs of repowering until the costs and benefits are fully included in base rates through a general rate case. Once the full costs and benefits are included in base rates, recovery of those elements would cease through the RTM, with the exception of PTCs. 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. After the next general rate case, the Company proposes to use the RTM to track the actual change in PTCs from the base level included in rates. Because PTCs are entirely dependent on the variable output of the repowered wind facilities and difficult to precisely forecast, tracking PTCs through the RTM ensures that customers receive their full value.

Under the RTM, the Company would begin deferring the costs and benefits associated with the wind repowering activity for each repowered wind facility in the month they go into service.

Q. Please summarize the Company's proposed accounting treatment for the wind equipment replaced by repowering.

A. The Company proposes to record the remaining book balances of replaced wind equipment in the accumulated depreciation reserve ("ADR"), and continue to recover these costs in rates.

Q. As the repowered wind facilities come into service, what are the annual, estimated deferral balances that would flow through the RTM?

A. As described more fully later in my testimony and exhibits, the Company is projecting estimated, annual revenue requirement benefits in Utah of up to $10.7 million by 2022, as summarized in Figure 1. The Company will capture the impacts of wind repowering through the RTM until they are included in base rates.

Figure 1

Repowering Estimated Revenue Requirement Cost (Benefit)
$thousands

	2019	2020	2021	2022
Total Company 1 Revenue Requirement	-$5,938	$6,443	-$9,380	-$25,184
2 Utah Allocated	-$2,531	$2,735	-$4,012	-$10,748
3 Utah EBA	-$215	-$4,136	-$5,869	-$7,732
4 Utah Deferral	-$2,316	$4,136	$1,857	-$3,017
5 Net Customer Benefit	-$2,531	$0	-$4,012	-$10,748

Q. How do the revenue requirement benefits in Figure 1 relate to Company witness Mr. Rick T. Link's analysis of revenue requirement savings from wind repowering?

A. Mr. Link conducted a revenue requirement differential analysis, while my analysis is a revenue requirement calculation based on his information.

Q. Is the RTM proposed here the same mechanism the Company proposes in the concurrently filed application for approval of a resource decision for new wind resources and associated transmission?

A. Yes. The Company proposes to use an RTM to track the costs and benefits associated with both wind repowering and the new wind and transmission resources discussed in the concurrently filed application. The Company proposes to separately track the costs and benefits of the two projects through different sections of the new tariff, in this case Schedule 97, which I provide in Exhibit RMP___(JKL-5). The Company proposes slight differences in the treatment of the deferral balances, applying the surcharge cap to wind repowering only.

REQUEST FOR APPROVAL OF RATEMAKING TREATMENT

Q. Under what authority is the Company proposing approval of the ratemaking treatment for the wind repowering project?

A. The Company seeks approval to defer the cost and benefits of the wind repowering project under Utah Code Ann. § 54-4-23, with the net benefits to be passed through the proposed RTM. Utah Code Ann. § 54-17-402 authorizes the Commission to approve a utility's proposed "resource decisions" outside of a general rate case. Utah Code Ann. § 54-17-403 authorizes cost recovery of the approved resource decision "in a general rate case or other appropriate proceeding." The Company proposes to use the annual RTM review, filed concurrently with the annual EBA review, as the proceeding referenced in Utah Code Ann. § 54-17-403 for cost recovery (or in this case, pass through of net benefit). This will address the proper ratemaking treatment to match the annual costs and benefits of the wind repowering project until the incremental costs and benefits are fully reflected in base rates, primarily including incremental capital and operating costs, and PTC benefits. Net power cost savings would currently be captured in the Company's EBA, however, to the extent the EBA is modified or eliminated, the Company would use the RTM to pass back any incremental net power cost savings not captured in the EBA. This mechanism will align the costs and benefits so that customers receive the full net benefits from the repowering project while shareholders receive appropriate cost recovery of the prudent investment. Once the full costs are reflected in base rates in a general rate case, the Company proposes that the RTM continue to track only year-to-year changes in PTCs to capture the full impact of the new PTCs.

Q. Why is it appropriate to provide the Commission and interested parties the opportunity to review and approve the ratemaking treatment for a resource decision before construction?

A. The benefit of the RTM being approved now is that it sets the process for consistent and fair treatment between customers and shareholders with respect to the ratemaking impacts of the wind repowering project. As a general policy matter, the Company believes that it is prudent and in the public interest to have regulatory review of large investments before implementation and construction. Such review avoids the need to address large investments in the context of a rate case along with the potential for disallowances of very large investments. For instance, in Docket No. 14-035-147, the Commission and interested parties reviewed and approved a stipulation for closure of the Deer Creek Mine, that was initially filed under the provisions of Utah Code Ann. § 54-17-402, in conjunction with the ratemaking treatment.

As the other Company witnesses have discussed, the wind repowering project has positive economic benefits for customers and is in the public interest due to the benefits of the incremental generation and PTCs. Without the proposed ratemaking treatment through the RTM, customers may not obtain the full benefits of the project, or a mismatch would occur between costs and benefits with customers receiving the immediate benefit of the incremental zero-cost energy production with no recognition of the capital costs, which would be borne by the shareholders. Currently, 100 percent of the benefits of incremental zero-cost generation from repowering would automatically flow through the EBA while the PTCs and costs associated with the investments would not be captured in rates and would flow to shareholders. Customers would be receiving benefits while shareholders would absorb a net cost. The deferral and RTM seeks to align the costs and benefits so that customers receive the full net benefits from the repowering project while shareholders receive appropriate cost recovery of the prudent investment. Moreover, the Company is proposing to implement the RTM concurrently with the EBA to match the timing for all costs and benefits in rates until reflected in base rates following a general rate case.

RESOURCE TRACKING MECHANISM

Q. Please describe the mechanics of the RTM.

A. Upon the completion of repowering at each wind resource, the Company will begin monthly deferrals of the associated costs and benefits in the RTM balancing account, which will operate on a calendar-year basis. On March 15 each year, the Company will file the RTM deferral balance from the prior calendar year, to be included in rates beginning May 1, on an interim basis. This schedule is aligned with the EBA, and the RTM review will continue on the same schedule as the EBA each year.

Q. Why is it important to link the timing of the RTM with the EBA?

A. Linking the RTM and the EBA helps match the increased production benefits of the repowered wind resources, which will flow through the EBA, with the costs of wind repowering. The RTM will minimize rate changes by using an annual filing date, as opposed to changing rates every time the Company completes repowering of a specific wind resource. Also, by filing the EBA and RTM concurrently, the Company can more readily combine the two mechanisms into a single line item on customer bills.

Q. What costs and revenues will be incorporated in the RTM deferral?

A. The deferral for each of the repowered wind resources will include the following revenue requirement components:

- Plant revenue requirement, consisting of:
    - Capital investment
    - ADR
    - Accumulated Deferred Income Tax ("ADIT")
    - Operations and Maintenance Expense ("O&M")

- Depreciation expense
- Property taxes
- Wyoming Wind Tax

- Net Power Cost (“NPC”) savings
- PTCs

These items are summarized in Exhibit RMP___(JKL-1). The Company will calculate the RTM deferral as the difference between the value included in base rates for these items and the new value taking into account the costs and benefits of repowered wind facilities as they are placed into service.

REVENUE REQUIREMENT COMPONENTS OF RTM

Q. Please describe how the RTM will track rate base components, which include the capital investment, ADR, and ADIT.

A. After a repowered wind resource is placed into service, the Company will defer the full amount of the capital investment, ADR, and ADIT related to repowering in the RTM. Once the Company has included some or all of the repowered wind resources in base rates through a future general rate case, the amount in rates will become the “wind base” plant balance that would be subtracted from the capital investment in subsequent annual RTM filings. The Company will use the net plant balance described above to calculate a return on investment using the most recent Commission-approved cost of capital and income tax rate.

Q. Please describe how the RTM will track depreciation expense.

A. The Company will include depreciation expense in the RTM deferral as the actual monthly plant-in-service balances associated with wind repowering, less the repowered wind base plant-in-service balance, multiplied by the current depreciation rates. Until a general rate case is filed, no depreciation expense associated with the repowered wind resources is reflected in base rates, so the full amount would be included in the RTM.

Q. Please describe how actual depreciation expense will be calculated.

A. The current depreciation rates will be applied to the gross electric plant-in-service ("EPIS") balance, associated with wind repowering, to calculate the depreciation expense. As existing equipment is replaced by repowering, the Company will transfer the replaced assets from gross EPIS to the ADR, thereby reducing depreciation expense on the existing investment until the next depreciation study. At that time, the Company will review the net plant balance for wind resources and propose new depreciation rates to recover both the repowering investment and the remaining investment in the replaced equipment. Because the repowering investment is projected to be less than the remaining investment, the initial depreciation expense after wind repowering will temporarily decrease until the Company implements new depreciation rates from its next depreciation study. The RTM deferral will reflect this decrease in depreciation expense. I provide more details on the proposed ratemaking treatment for replaced equipment later in my testimony.

Q. Please estimate the amount of the temporary decrease in depreciation expense.

A. As of December 31, 2016, the Company had approximately $2.0 billion gross investment in wind with approximately $67 million of annual depreciation expense. Approximately $1.2 billion of gross electric plant-in-service will be replaced as part of the wind repowering project and transferred to the ADR. Wind repowering will cost approximately $1.1 billion, so gross plant will decrease from $2.0 billion to $1.9

billion, thereby reducing annual depreciation expense from approximately $67 million to approximately $64 million based on the current depreciation rates.

Q. What happens to depreciation expense after the initial implementation of the wind repowering project?

A. The reduced depreciation expense will continue until the rates from the next depreciation study are approved by the Commission and included in base rates. The depreciable lives and depreciation rates of all assets, including the Company's wind assets scheduled for repowering, will be reviewed as part of the next depreciation study to be filed with this Commission in the fall of 2018. As part of the depreciation study, the depreciation rates will be revised to recover the remaining wind plant balances, including the impacts of the debit balance in the ADR, over the life of the assets.

Q. How will the RTM reflect incremental O&M expense?

A. As repowered wind resources are placed into service, the Company will compare the actual O&M expense for each wind resource to the 2014-2017 historical four-year average of O&M expense by wind resource. The difference will be included in the RTM deferral.

Q. Why did the Company select a four-year average of calendar years 2014-2017?

A. A pre-repowering four-year historical average helps to smooth variations in O&M expense that can occur year to year. Also, because repowering may impact wind resources during 2018 and 2019, those years should be excluded for an accurate reflection of the average wind O&M before wind repowering.

Q. How will the RTM reflect property taxes?

A. The Company will calculate property taxes associated with the repowered wind resources by taking the monthly average of the capital investment less ADR included in the RTM deferral multiplied by the average property tax rate from the Company's last general rate case.

Q. How will the RTM reflect Wyoming wind taxes?

A. The Company will calculate the Wyoming wind tax by taking the incremental generation associated with wind repowering multiplied by the Wyoming wind tax rate.

NPC AND PTC BENEFITS IN THE RTM

Q. Please explain the calculation of the incremental NPC benefits in the RTM.

A. Wind repowering will result in additional zero-fuel-cost energy, reducing total NPC. Under the current EBA, 100 percent of the incremental NPC benefits of the wind repowering project will be credited to customers, with zero percent assigned to the Company. Based on the Commission order in Docket No. 09-035-15, the current EBA pilot structure extends through December 31, 2019. If at the conclusion of the EBA pilot period, the EBA structure is modified such that less than 100 percent of the incremental NPC benefits is credited to customers through the EBA, the Company proposes to capture any of the incremental NPC benefits in the RTM that are not credited to customers through the EBA, so that customers continue to receive 100 percent of the net benefits of the wind repowering project until the costs and benefits of the wind repowering project are fully reflected in rates.

In order to credit customers with 100 percent of incremental NPC benefits the Company would calculate the incremental NPC benefit in the RTM as the increased generation achieved by repowering, applied to the total wind generation to derive the incremental energy on a per-plant basis. The calculation is described in Exhibit RMP___(JKL-4).

The Company would then value the incremental energy using a monthly market price less wind integration costs, and the RTM will pass the appropriate percentage of that value through to customers.

Q. What market price would the Company use to value the incremental energy?

A. The market price used in the calculation would be dependent on the physical location of the wind resource and the time of the generation. If the wind resource is located on the west side of the Company's system, the monthly Mid-Columbia heavy load hour ("HLH") and light load hour ("LLH") market price would be used. If the wind resource is located on the east side of the Company's system, the monthly Four Corners HLH and LLH market price would be used. Additionally, the market price would be reduced by the wind integration costs from the most recent integration study, which currently is from the Company's 2017 Integrated Resource Plan.

Q. Please explain the calculation of the PTCs that will be included in the RTM.

A. Currently, the IRS rate for PTCs is $24 per megawatt-hour, and PTCs are generally applicable for a period of 10 years after a wind resource is operational. The PTC rate is applied to the actual megawatt-hours of generation from the eligible wind turbine resources. This produces a tax credit that can be used to offset a company's income tax expense under IRS guidelines. To derive the revenue requirement value of the tax credit, the PTC value must be grossed-up by the Company's tax gross-up rate. The Company will use the tax gross-up rate from its most recent general rate case to calculate the value of the PTCs from wind repowering. The RTM will reflect the value for the grossed-up PTCs.

Q. Why should the RTM track the benefits of the PTCs on an ongoing basis?

A. The amount of PTCs received is entirely dependent on the amount of the generation at eligible facilities. The generation is highly dependent on weather, varying from year-to-year as weather patterns fluctuate. Accordingly, because the PTCs are significant and actual output is beyond the control of the Company, the Company proposes to use the RTM to track and true-up PTCs on an ongoing basis.

Q. Do the base rates that are currently in place include PTCs for the existing resources?

A. Yes. These resources qualified for PTCs when they initially began commercial operation. A value based on the generation from these projects during the test period is currently included in base rates. The Company is not proposing to remove this value from base rates through this mechanism. The RTM is intended to track the PTCs associated with repowered wind resources only.

Q. How will the Company treat wind repowering costs incurred before the in-service dates of the repowered resources?

A. As described in the testimony and exhibits of Mr. Hemstreet and Mr. Link, the Company will incur minor repowering costs before the in-service dates of the repowered wind resources. These costs were included in the Company's economic analysis. Most of the costs are due to reduced generation from the facilities before and during repowering, and the associated loss of PTCs. These costs will be included in the EBA. Because these costs are part of the overall project, which will benefit customers, it is appropriate that customers pay for them. The impact from the current PTCs ending will be borne entirely by the Company because the benefits are currently built into rates.

RTM CALCULATION AND STRUCTURE

Q. Have you prepared an exhibit that illustrates the calculation and structure of the RTM on a year-by-year basis?

A. Yes. Exhibit RMP___(JKL-2) provides an illustrative example of the calculation of the RTM on an annual basis. The annual amounts will be the sum of the monthly amounts shown in Exhibit RMP___(JKL-3), and the individual lines are described as part of that exhibit.

Q. Please explain Exhibit RMP___(JKL-3).

A. Exhibit RMP___(JKL-3) is an example of the RTM's monthly calculation. The RTM deferral will be adjusted after a general rate case to exclude amounts that are recovered as part of base rates in the rate case to assure against double-recovery. For items partially recovered in base rates, such as capital investments included for part of the test period, the portion included in the test period will be removed as of the effective date of the general rate case. Page 5 of Exhibit RMP___(JKL-3) includes an overview of the total plant revenue requirement, net power cost, and PTC sections.

Once per year on a calendar-year basis, the Company will sum the monthly RTM revenue requirement entries to prepare the annual RTM application for filing with the Commission on March 15, with an interim rate effective date that corresponds with the EBA application (May 1). 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.

Q. How will the costs and benefits associated with the wind repowering project be allocated to Utah customers?

A. The Company will use Utah's applicable inter-jurisdictional allocation factors to allocate total-company revenue requirement to Utah based on the current Commission-approved allocation methodology. Because the allocation factors are dynamic and change with variations in jurisdictional loads, the Company is proposing that the allocation factors used in the RTM match the allocation factors used in the calculation of the EBA.

Q. How will the Company calculate rates to credit or recover RTM balances?

A. The Company will file a separate rate to credit or recover the net amount in the RTM deferral. The Company proposes to use the same class allocation and rate design as used for the annual EBA filing. For billing purposes, the EBA and RTM rates could be consolidated on the customer bill.

Q. Has the Company prepared a tariff for the RTM?

A. Yes. The Company has prepared a tariff for implementation of the RTM. The tariff is identified as Schedule 97A, Resource Tracking Mechanism - Wind Repowering, and is included in my testimony as Exhibit RMP___(JKL-5).

Q. What procedures do you envision for an application to adjust the RTM?

A. The Company expects that the Commission will docket and notice an RTM application similar to other tariff filings. The Commission staff and intervening parties will have an opportunity to examine the application and submit data requests. The Company will work with the parties, which could result in a consensus recommendation that will be presented to the Commission, or the matter could be scheduled for hearing if there are contested issues. The important aspect of the proposed RTM schedule is that it be processed concurrently with the EBA to preserve the matching principle for costs and benefits.

Q. Would stakeholders be able to challenge the general prudence of wind repowering when the Company files to change rates under the RTM?

A. No. The Company is seeking approval in this filing that the decision to repower most of the Company's wind facilities is reasonable, prudent, and in the public interest. If the Commission makes this finding in this proceeding, review of the specific costs included in the RTM would be subject to Utah Code Ann. § 54-17-403, which provides that retail rates may include the state's share of the costs of the approved resource decision up to the projected costs in this Application. Any increase from the projected costs would be subject to review by the Commission under Utah Code Ann. § 54-7-12. The Commission may only disallow some or all costs if the Commission finds the Company's actions in implementing the approved resource decision were not prudent because of new information or changed circumstances, or if the Company was responsible for material misrepresentation or concealment in connection with the resource approval process.

ACCOUNTING TREATMENT FOR REPLACED EQUIPMENT

Q. Please explain the Company's proposed accounting treatment for equipment replaced by wind repowering.

A. As existing wind generation equipment is replaced during the repowering process, the

Company will follow accounting treatment consistent with FERC regulations and allowed by generally accepted accounting principles. The original investment will be transferred from FERC account 101, EPIS, to Account 108, ADR, by crediting EPIS and debiting the ADR. This entry will not change the Company's net plant balance, but it will shift the ADR from a negative to a positive balance. The remaining original investment plus new capital additions will be depreciated using current depreciation rates until the Company's next depreciation study.

Q. Is the Company requesting continued cost recovery of plant balances associated with equipment replaced in the wind repowering project?

A. Yes. The existing net plant is currently in rates and should remain in rates. The Company's decision to pursue the wind repowering project is dependent on the Company continuing to recover its current investment in its wind facilities. The equipment replacement does not change the net book balance of the existing assets pre-repowering, and the incremental investment to repower these wind resources will be recovered through the RTM until the costs are captured through the general rate case process.

Q. How would the Company treat any salvage value of the replaced equipment?

A. The Company would treat the salvage value of the equipment under the same accounting guidelines. To the extent that any salvage value is obtained from the equipment, then the value would be credited to the ADR, reducing the net plant balance.

INTER-JURISDICTIONAL COST ALLOCATION

Q. How will the Company allocate the investment in the wind repowering project to the state jurisdictions PacifiCorp serves?

A. Currently, the Company's investment in wind generation facilities is treated as a system resource under the approved 2017 Protocol Allocation Agreement. That approved methodology will continue for ratemaking purposes through 2019. The same treatment will apply to new investments that occur in that period. After that time period, the then-applicable allocation methodology approved by the Commission would govern.

The Company's analysis demonstrates that the wind repowering project delivers net system benefits, and the Company believes that the repowered wind facilities should continue to be allocated across the six-state service territory on a system basis unless there is an agreement through the Multi-State Process to do otherwise.

CONCLUSION

Q. Please summarize your testimony.

A. The wind repowering project presents an excellent opportunity to provide customers with additional zero-fuel-cost wind energy for an extended period of time. To match investment and operational costs with the benefits of the repowered wind resources until the costs and benefits are fully included in base rates through a general rate case, the Company proposes to defer all costs and benefits and to implement the RTM. The matching of the costs and benefits through the RTM is fair to customers and shareholders.

Additionally, allowing the Company to assign replaced equipment to the ADR from plant-in-service and continue rate recovery of the plant balances over the useful life of the repowered wind investment life is just and reasonable and allows the Company to pursue the wind repowering project.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission approve the wind repowering project and the Company's proposals for ratemaking treatment, and for the continued recovery of the replaced equipment. Approval will provide certainty to the Company and enable it to move forward with the wind repowering project.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jeffrey K. Larsen

Revenue Requirement Overview – Wind Repowering

June 2017

Resource Tracking Mechanism

Revenue Requirement Overview – Wind Repowering

Category	Base	New	Deferral
Capital Investment	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.	Actual monthly plant-in-service balances associated with wind repowering, beginning with first repowering assets placed in service.	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.
Accumulated Depreciation Reserve	Same as capital investment.	Monthly depreciation reserve of repowered assets.	
Accumulated Deferred Income Tax	Same as capital investment.	Actual accumulated deferred income tax balances associated with the repowering investment.	
Operation & Maintenance Expense	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).	Actual O&M expense for wind projects.	
Depreciation Expense	Zero.	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.	
Property Taxes	Zero.	Capital Investment deferral less the Depreciation Reserve deferral multiplied by the average property tax rate from the last rate case.	
Wind Tax	Zero.	Incremental energy production MWh associated with repowering multiplied by the wind tax rate.	
NPC Savings	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 Exhibit RMP__(TJH-3)).	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.	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.
PTC	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.	Actual MWh eligible for PTC produced by repowered wind plants multiplied by the production tax rate.	Difference between the base and actual. Tracked until repowering PTCs have expired, and have been reset to zero in base rates.
RTM Cap	N/A	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.	

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jeffrey K. Larsen

Example Annual RRM Deferral Calculation – Revenue Requirement

June 2017

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

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

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	$-Thousands		2019 Repowering				2020 Repowering				2021 Repowering				2022 Repowering			
Line No.		Reference	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated	Total Company	Factor	Factor %	Utah Allocated
	Plant Revenue Requirement																	
1	Capital Investment	Footnote 1	171,567	SG	42.6283%	73,136	986,120	SG	42.6283%	420,366	1,132,769	SG	42.6283%	482,880	1,137,288	SG	42.6283%	484,807
2	Depreciation Reserve	Footnote 1	(939)	SG	42.6283%	(400)	(23,511)	SG	42.6283%	(10,023)	(59,031)	SG	42.6283%	(25,164)	(96,879)	SG	42.6283%	(41,298)
3	Accumulated DIT Balance	Footnote 1	(43,669)	SG	42.6283%	(18,615)	(192,063)	SG	42.6283%	(81,873)	(263,671)	SG	42.6283%	(112,399)	(307,628)	SG	42.6283%	(131,137)
4	Net Rate Base	sum of lines 1-3	126,959			54,120	770,545			328,470	810,067			345,318	732,781			312,372
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	13,520			5,763	82,057			34,979	86,265			36,774	78,035			33,265
7	Wholesale Wheeling Revenue	Footnote 4	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-
8	Operation & Maintenance	Footnote 3	583	SG	42.6283%	248	4,379	SG	42.6283%	1,867	3,864	SG	42.6283%	1,647	844	SG	42.6283%	360
9	Depreciation	Footnote 3 & 6	8,454	SG	42.6283%	3,604	33,279	SG	42.6283%	14,186	37,778	SG	42.6283%	16,104	37,947	SG	42.6283%	16,176
10	Property Taxes	Footnote 3	-	GPS	42.4704%	-	7,506	GPS	42.4704%	3,188	8,375	GPS	42.4704%	3,557	8,115	GPS	42.4704%	3,446
11	Wind Tax	Footnote 3	60	SG	42.6283%	26	206	SG	42.6283%	88	251	SG	42.6283%	107	251	SG	42.6283%	107
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**22,618**			**9,641**	**127,427**			**54,308**	**136,533**			**58,188**	**125,192**			**53,354**
	Net Power Cost																	
13	NPC Incremental Savings	Footnote 3	(505)	SG	42.6283%	(215)	(9,703)	SG	42.6283%	(4,136)	(13,767)	SG	42.6283%	(5,869)	(18,137)	SG	42.6283%	(7,732)
	PTC Benefit																	
14	PTC Benefit	Footnote 3	(17,405)	SG	42.6283%	(7,420)	(69,048)	SG	42.6283%	(29,434)	(81,995)	SG	42.6283%	(34,953)	(82,052)	SG	42.6283%	(34,977)
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	(17,405)			(7,420)	(69,048)			(29,434)	(81,995)			(34,953)	(82,052)			(34,977)
17	Gross- up for taxes	line 16 * (line 32 - 1)	(10,646)			(4,538)	(42,232)			(18,003)	(50,151)			(21,378)	(50,186)			(21,393)
18	PTC Revenue Requirement	sum of lines 16 and 17	(28,051)			(11,958)	(111,280)			(47,437)	(132,146)			(56,331)	(132,238)			(56,371)
19	**Rev. Requirement**	sum of lines 12, 13, 18	(5,938)			(2,531)	6,443			2,735	(9,380)			(4,012)	(25,184)			(10,748)
	Adjustment for EBA Pass-through																	
20	NPC Incremental Savings	line 13				(215)				(4,136)				(5,869)				(7,732)
21	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%				100%				100%
22	EBA Pass-through	line 20 * line 21				(215)				(4,136)				(5,869)				(7,732)
23	**Rev. Reqt. after EBA Pass-through**	line 19 - line 22				(2,316)				6,871				1,857				(3,017)
24	**Total Deferral - UT Share**	Footnote 5				(2,316)				4,136				1,857				(3,017)
25	**Net Customer Benefit**	line 22 + line 24				(2,531)				-				(4,012)				(10,748)
	Deferral Balance - UT Share																	
26	Beginning Deferral Balance	line 30 of previous year				-				(2,352)				3,356				4,044
27	Monthly Deferral	Footnote 5				(2,316)				4,136				1,857				(3,017)
28	Deferral Collection	Footnote 3				-				1,568				(1,453)				(3,815)
29	Carrying Charge	Footnote 3				(36)				4				285				77
30	**Ending Deferral Balance**	sum of lines 26-29				(2,352)				3,356				4,044				(2,710)

31	Federal/State Combined Tax Rate	JKL_4, line 5	37.951%	
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4, 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_4, line 4	10.649%	13-035-184 Capital Structure & Cost - Ordered
35	Property Tax Rate	JKL_4, line 14	0.77%	Property Tax Expense as a percent of Net plant from 13-035-184
36	Utah SG Factor	JKL_4, line 15	42.6283%	
37	Utah GPS Factor	JKL_4, 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-3)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jeffrey K. Larsen

Example Monthly RRM Deferral Calculation – Revenue Requirement

June 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		-	-	-	-	-	-	154,212	154,212	154,212	611,361	984,807	984,807
2	Depreciation Reserve		-	-	-	-	-	-	(428)	(857)	(1,285)	(2,983)	(5,719)	(8,454)
3	Accumulated DIT Balance		-	-	-	-	-	-	(80,619)	(80,619)	(120,929)	(120,929)	(120,929)	(161,239)
4	Net Rate Base	sum of lines 1-3	-	-	-	-	-	-	73,164	72,736	31,998	487,448	858,159	815,114
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	-	-	-	-	-	-	-	649	645	284	4,326	7,616
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		-	-	-	-	-	-	26	26	26	119	193	193
9	Depreciation	Footnote 5	-	-	-	-	-	-	428	428	428	1,698	2,736	2,736
10	Property Taxes	Prior December (line 1 + line 2) x line 35	-	-	-	-	-	-	-	-	-	-	-	-
11	Wind Tax		-	-	-	-	-	-	3	3	3	12	20	20
12	**Total Plant Revenue Requirement**	sum of lines 6-11	-	-	-	-	-	-	457	1,106	1,102	2,114	7,275	10,564
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	-	-	-	-	-	-	(22)	(22)	(22)	(103)	(167)	(167)
	PTC Benefit													
14	PTC Benefit		-	-	-	-	-	-	(769)	(769)	(769)	(3,558)	(5,770)	(5,770)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	-	-	-	-	-	-	(769)	(769)	(769)	(3,558)	(5,770)	(5,770)
17	Gross- up for taxes	line 16 * (line 31 - 1)	-	-	-	-	-	-	(470)	(470)	(470)	(2,176)	(3,529)	(3,529)
18	PTC Revenue Requirement	sum of line 16 and 17	-	-	-	-	-	-	(1,239)	(1,239)	(1,239)	(5,734)	(9,299)	(9,299)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	-	-	-	-	-	-	(805)	(156)	(160)	(3,724)	(2,192)	1,098
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	-	-	-	-	-	-	(22)	(22)	(22)	(103)	(167)	(167)
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	-	-	-	-	-	-	(22)	(22)	(22)	(103)	(167)	(167)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	-	-	-	-	-	-	(783)	(133)	(137)	(3,620)	(2,025)	1,265
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	-	-	-	-	-	-	(334)	(57)	(59)	(1,543)	(863)	539
25	**Net Customer Benefit**	line 22 * line 36 + line 24	-	-	-	-	-	-	(343)	(66)	(68)	(1,587)	(934)	468
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	-	-	-	-	-	-	-	(334)	(393)	(454)	(2,003)	(2,878)
27	Monthly Deferral	line 24	-	-	-	-	-	-	(334)	(57)	(59)	(1,543)	(863)	539
28	Deferral Collection	Footnote 3	-	-	-	-	-	-	-	-	-	-	-	-
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	-	-	-	-	-	-	(1)	(2)	(2)	(6)	(12)	(13)
30	**Ending Deferral Balance**	sum of lines 26-29	-	-	-	-	-	-	(334)	(393)	(454)	(2,003)	(2,878)	(2,352)
31	Federal/State Combined Tax Rate	JKL_4, line 5	37.951%											
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4, line 6	1.6116											
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2 line 33	6.00%											
34	Pretax Return	JKL_4, line 4	10.649%											
35	Property Tax Rate	JKL_4, line 14	0.77%											
36	Utah SG Factor	JKL_4, line 15	42.6283%											
37	Utah GPS Factor	JKL_4, 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		984,807	984,807	984,807	984,807	984,807	984,807	987,957	987,957	987,957	987,957	987,957	1,131,152
2	Depreciation Reserve		(11,190)	(13,926)	(16,661)	(19,397)	(22,132)	(24,868)	(27,613)	(30,357)	(33,102)	(35,846)	(38,591)	(41,733)
3	Accumulated DIT Balance		(161,239)	(161,239)	(181,788)	(181,788)	(181,788)	(202,337)	(202,337)	(202,337)	(222,886)	(222,886)	(222,886)	(243,436)
4	Net Rate Base	sum of lines 1-3	812,378	809,643	786,358	783,622	780,887	757,602	758,007	755,263	731,969	729,224	726,480	845,983
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	7,234	7,209	7,185	6,978	6,954	6,930	6,723	6,727	6,702	6,496	6,471	6,447
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		361	361	361	361	361	361	361	361	361	361	361	406
9	Depreciation	Footnote 5	2,736	2,736	2,736	2,736	2,736	2,736	2,745	2,745	2,745	2,745	2,745	3,142
10	Property Taxes	Prior December (line 1 + line 2) x line 35	625	625	625	625	625	625	625	625	625	625	625	625
11	Wind Tax		17	17	17	17	17	17	17	17	17	17	17	19
12	**Total Plant Revenue Requirement**	sum of lines 6-11	10,973	10,949	10,924	10,718	10,693	10,669	10,471	10,475	10,451	10,244	10,220	10,640
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(900)
	PTC Benefit													
14	PTC Benefit		(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(6,405)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(5,695)	(6,405)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,483)	(3,918)
18	PTC Revenue Requirement	sum of line 16 and 17	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(9,178)	(10,323)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	995	970	946	739	715	691	493	497	473	266	241	(583)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(900)
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	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(900)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	1,795	1,771	1,746	1,540	1,515	1,491	1,294	1,297	1,273	1,066	1,042	317
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	341	341	341	341	341	341	341	341	341	341	341	384
25	**Net Customer Benefit**	line 22 * line 36 + line 24	-	-	-	-	-	-	-	-	-	-	-	-
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	(2,352)	(2,022)	(1,690)	(1,356)	(1,021)	(489)	46	584	1,124	1,668	2,213	2,762
27	Monthly Deferral	line 24	341	341	341	341	341	341	341	341	341	341	341	384
28	Deferral Collection	Footnote 3	-	-	-	-	196	196	196	196	196	196	196	196
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	(11)	(9)	(8)	(6)	(5)	(2)	1	3	6	9	11	14
30	**Ending Deferral Balance**	sum of lines 26-29	(2,022)	(1,690)	(1,356)	(1,021)	(489)	46	584	1,124	1,668	2,213	2,762	3,356
31	Federal/State Combined Tax Rate	JKL_4, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4, line 6												
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2 line 33												
34	Pretax Return	JKL_4, line 4												
35	Property Tax Rate	JKL_4, line 14												
36	Utah SG Factor	JKL_4, line 15												
37	Utah GPS Factor	JKL_4, line 16												

Rocky Mountain Power
Exhibit RMP___(JKL-3) Page 3 of 5
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

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		1,131,152	1,131,152	1,131,152	1,131,152	1,131,152	1,131,152	1,135,034	1,135,034	1,135,034	1,135,034	1,135,034	1,135,034
2	Depreciation Reserve		(44,876)	(48,018)	(51,161)	(54,303)	(57,445)	(60,588)	(63,742)	(66,896)	(70,050)	(73,203)	(76,357)	(79,511)
3	Accumulated DIT Balance		(243,436)	(243,436)	(256,926)	(256,926)	(256,926)	(270,416)	(270,416)	(270,416)	(283,907)	(283,907)	(283,907)	(297,397)
4	Net Rate Base	sum of lines 1-3	842,840	839,698	823,065	819,923	816,780	800,148	800,876	797,722	781,078	777,924	774,770	758,126
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	7,508	7,480	7,452	7,304	7,276	7,248	7,101	7,107	7,079	6,932	6,904	6,876
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		322	322	322	322	322	322	322	322	322	322	322	322
9	Depreciation	Footnote 5	3,142	3,142	3,142	3,142	3,142	3,142	3,154	3,154	3,154	3,154	3,154	3,154
10	Property Taxes	Prior December (line 1 + line 2) x line 35	698	698	698	698	698	698	698	698	698	698	698	698
11	Wind Tax		21	21	21	21	21	21	21	21	21	21	21	21
12	**Total Plant Revenue Requirement**	sum of lines 6-11	11,691	11,663	11,635	11,487	11,459	11,432	11,295	11,302	11,274	11,126	11,098	11,070
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)
	PTC Benefit													
14	PTC Benefit		(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)	(6,833)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)	(4,179)
18	PTC Revenue Requirement	sum of line 16 and 17	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)	(11,012)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	(469)	(497)	(524)	(672)	(700)	(728)	(864)	(857)	(885)	(1,033)	(1,061)	(1,089)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)
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	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	679	651	623	475	447	419	283	290	262	114	86	58
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	288	276	264	201	190	178	120	122	110	48	36	24
25	**Net Customer Benefit**	line 22 * line 36 + line 24	(201)	(213)	(225)	(288)	(299)	(311)	(369)	(367)	(379)	(442)	(453)	(465)
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	3,356	3,857	4,349	4,831	5,253	5,190	5,115	4,982	4,851	4,707	4,499	4,278
27	Monthly Deferral	line 24	288	276	264	201	190	178	120	122	110	48	36	24
28	Deferral Collection	Footnote 3	196	196	196	196	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	17	19	22	24	27	27	27	26	25	24	23	22
30	**Ending Deferral Balance**	sum of lines 26-29	3,857	4,349	4,831	5,253	5,190	5,115	4,982	4,851	4,707	4,499	4,278	4,044
31	Federal/State Combined Tax Rate	JKL_4, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4, line 6												
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2 line 33												
34	Pretax Return	JKL_4, line 4												
35	Property Tax Rate	JKL_4, line 14												
36	Utah SG Factor	JKL_4, line 15												
37	Utah GPS Factor	JKL_4, 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		1,135,034	1,135,034	1,135,034	1,135,034	1,135,034	1,135,034	1,140,444	1,140,444	1,140,444	1,140,444	1,140,444	1,140,444
2	Depreciation Reserve		(82,665)	(85,819)	(88,973)	(92,127)	(95,281)	(98,435)	(101,605)	(104,776)	(107,946)	(111,117)	(114,287)	(117,458)
3	Accumulated DIT Balance		(297,397)	(297,397)	(304,218)	(304,218)	(304,218)	(311,039)	(311,039)	(311,039)	(317,860)	(317,860)	(317,860)	(324,680)
4	Net Rate Base	sum of lines 1-3	754,972	751,818	741,843	738,689	735,535	725,560	727,801	724,630	714,639	711,468	708,298	698,306
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	6,728	6,700	6,672	6,583	6,555	6,527	6,439	6,459	6,431	6,342	6,314	6,286
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		70	70	70	70	70	70	70	70	70	70	70	70
9	Depreciation	Footnote 5	3,154	3,154	3,154	3,154	3,154	3,154	3,171	3,171	3,171	3,171	3,171	3,171
10	Property Taxes	Prior December (line 1 + line 2) x line 35	676	676	676	676	676	676	676	676	676	676	676	676
11	Wind Tax		21	21	21	21	21	21	21	21	21	21	21	21
12	**Total Plant Revenue Requirement**	sum of lines 6-11	10,649	10,621	10,593	10,505	10,477	10,449	10,377	10,397	10,369	10,280	10,252	10,224
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JKL-4	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)
	PTC Benefit													
14	PTC Benefit		(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)	(6,838)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)	(4,182)
18	PTC Revenue Requirement	sum of line 16 and 17	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)	(11,020)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	(1,882)	(1,910)	(1,938)	(2,027)	(2,055)	(2,083)	(2,154)	(2,135)	(2,163)	(2,251)	(2,279)	(2,308)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)
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	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)	(1,511)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	(371)	(399)	(427)	(515)	(543)	(571)	(643)	(623)	(651)	(740)	(768)	(796)
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	(159)	(171)	(183)	(221)	(233)	(245)	(275)	(267)	(279)	(316)	(328)	(340)
25	**Net Customer Benefit**	line 22 * line 36 + line 24	(803)	(815)	(827)	(865)	(877)	(889)	(919)	(911)	(923)	(961)	(973)	(985)
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	4,044	3,626	3,194	2,747	2,261	1,703	1,130	524	(77)	(693)	(1,350)	(2,022)
27	Monthly Deferral	line 24	(159)	(171)	(183)	(221)	(233)	(245)	(275)	(267)	(279)	(316)	(328)	(340)
28	Deferral Collection	Footnote 3	(280)	(280)	(280)	(280)	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	21	18	16	14	12	9	6	3	(0)	(3)	(7)	(10)
30	**Ending Deferral Balance**	sum of lines 26-29	3,626	3,194	2,747	2,261	1,703	1,130	524	(77)	(693)	(1,350)	(2,022)	(2,710)
31	Federal/State Combined Tax Rate	JKL_4, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JKL_4, line 6												
33	Deferred Balance Carrying Charge	UT EBA rate; see JKL_2 line 33												
34	Pretax Return	JKL_4, line 4												
35	Property Tax Rate	JKL_4, line 14												
36	Utah SG Factor	JKL_4, line 15												
37	Utah GPS Factor	JKL_4, line 16												

Total Plant Revenue Requirement (Lines 1-12, 34):
Exhibit JKL-3 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-4.

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-4)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jeffrey K. Larsen

Example Monthly RRM Deferral Calculation – Capital Structure and Property Tax Rate

June 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-3, page 2 of 2)
$Incremental\ Gen_{HLH}$ *= 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
R TM NPC Benefit = The NPC repowering benefit absorbed by the Company in the EBA as a result of the sharing band

Rocky Mountain Power
Exhibit RMP___(JKL-5)
Docket No. 17-035-39
Witness: Jeffrey K. Larsen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jeffrey K. Larsen

Proposed Schedule

June 2017

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 97

STATE OF UTAH

Resource Tracking Mechanism (RTM)
Wind Repowering

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the terms contained in this Tariff. All retail tariff rate schedules shall be subject to the rate elements in this Schedule, which tracks the costs and benefits associated with the wind repowering projects as approved in Docket Number 17-035-39.

DEFINITIONS:

RTM: the Resource Tracking Mechanism.

RTM Filing Date: The RTM Filing Date shall be on or about March 15 of each year under normal circumstances.

RTM Rate Effective Date: The RTM Rate Effective Date shall be May 1 of each year on an interim basis under normal circumstances, subject to investigation, protest, hearing and final order of the Commission. The Company may file a properly executed application with the Commission to implement the RTM Rate Adjustment on an interim basis, and if approved by the Commission, the RTM Rate Adjustment shall continue until a final order is issued by the Commission and is adjusted accordingly.

Deferred RTM Comparison Period: The historical 12-month period beginning January 1 and extending through December 31 preceding the RTM Rate Effective Date.

(continued)

RTM Deferral: The RTM Deferral for wind repowering is the sum of the Plant Revenue Requirement, RTM NPC Benefits and RTM PTC Benefits for the resources approved for recovery in this mechanism that are not otherwise reflected in retail rates. Once the Plant Revenue Requirement, RTM NPC Benefits and RTM PTC Benefits for eligible resources are reflected in base rates following a general rate case, the RTM Deferral will consist of the difference between the Base PTC Benefits set in base rates and New PTC Benefits calculated from actual megawatt-hour generation for repowered turbines. The applicable FERC accounts where the costs and benefits will most likely be booked, as defined in Code of Federal Regulations, Subchapter C, Part 101, are listed, where applicable, with the noted clarifications and exclusions.

Plant Revenue Requirement: Consists of the capital investment, accumulated depreciation reserve, accumulated deferred income tax, operations and maintenance expense, depreciation expense, Wyoming wind generation tax and property tax associated with the wind repowering projects.

Net Power Cost or NPC: Comprised of fuel, wholesale purchases and sales of electricity (including financial hedges), wheeling expenses, and wholesale purchases and sales of natural gas (including financial hedges), as provided for in Schedule 94, Energy Balancing Account (EBA).

RTM NPC Benefit: 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.

Incremental Generation: The estimated increase in generation at the wind plant due to repowering. The Incremental Generation is calculated as the new wind plant generation MWh less the Base Wind Plant Generation MWh.

Project Generation Increase (%): The percentage change in energy at the wind plant due to repowering.

Incremental Generation$_{\mathbf{HLH}}$: The increase in generation at the wind plant due to repowering during heavy load hours.

Incremental Generation$_{\mathbf{LLH}}$: The increase in generation at the wind plant due to repowering during light load hours.

Monthly Market Price$_{\mathbf{HLH}}$: The heavy load hour monthly market price.

Monthly Market Price$_{\mathbf{LLH}}$: The light load hour monthly market price.

(continued)

Integration Costs: The wind integration costs from the most recent Integrated Resource Plan.

Production Tax Credits or PTCs: Federal tax credits for energy produced from wind energy facilities. The credit is generally applicable for a period of 10 years after the wind facility is operational and is calculated by taking the actual megawatt-hours of generation from repowered wind turbines multiplied by the applicable IRS rate.

New PTC Benefits: Calculated as actual MWh eligible for PTCs produced by repowered wind plants multiplied by the production tax rate. This amount is grossed up using the tax gross-up rate from the most recently approved general rate case.

Base PTC Benefits: Calculated as the PTCs related to the wind repowering project that have been included in base rates through a general rate case. This amount is grossed up using the tax gross-up rate from the most recently approved general rate case. Before the next general rate case, the Base PTC Benefits amount will be zero. After rates from the general rate case become effective, the Base PTC Benefit will be the amount included in the test period, beginning on the rate effective date. Applicable FERC Account: FERC 409xxxx- Income Taxes, Utility Operating Income

New Capital Investment: The actual monthly electric plant-in-service balances associated with the wind repowering.. Applicable FERC Accounts: FERC 101xxxx - Electric Plant in Service, FERC Sub Accounts: 340xxxx through 347xxxx - Other Production Plant

Base Capital Investment: The amount booked into electric plant-in-service related to the wind repowering projects that have been included in base rates through a general rate case. After rates from the general rate case become effective, the Base Capital Investment will be the amount included in the test period, beginning on the rate effective date. Applicable FERC Accounts: FERC 101xxxx - Electric Plant in Service, FERC Sub Accounts: 340xxxx through 347xxxx - Other Production Plant

New Accumulated Depreciation Reserve: The monthly accumulated depreciation reserve of the repowered assets. Applicable FERC Accounts: FERC 108xxxx - Accumulated Depreciation Reserve, FERC Sub Accounts: 340xxxx through 347xxxx - Other Production Plant

Base Accumulated Depreciation Reserve: The amount booked into accumulated depreciation reserve related to the wind repowering projects that have been included in base rates through a general rate case. After rates from the general rate case become effective, the Base Accumulated Depreciation Reserve will be the amount included in the test period, beginning on the rate effective date. Applicable FERC Accounts: FERC 108xxxx - Accumulated Depreciation Reserve, FERC Sub Accounts: 340xxxx through 347xxxx - Other Production Plant

New Accumulated Deferred Income Tax: The actual accumulated deferred income tax balances associated with the repowering investment. Applicable FERC Account: FERC 282xxxx - ADIT Other Property

(continued)

Base Accumulated Deferred Income Tax: The amounts booked into accumulated deferred income tax related to the wind repowering projects that have been included in base rates through a general rate case. After rates from the general rate case become effective, the Base Accumulated Deferred Income Tax will be the amount included in the test period, beginning on the rate effective date. Applicable FERC Account: FERC 282xxxx - ADIT Other Property

New Operations and Maintenance Expense: The actual operations and maintenance expense incurred associated with the wind repowering projects. Applicable FERC Accounts: FERC 546xxxx, 548xxxx through 554xxxx - Other Power Generation, FERC 556xxxx, 557xxxx - Other Power Supply

Base Operations and Maintenance Expense: The four year historical average of calendar years 2014, 2015, 2016, and 2017 associated with wind operations. Applicable FERC Accounts: FERC 546xxxx, 548xxxx through 554xxxx - Other Power Generation, FERC 556xxxx, 557xxxx - Other Power Supply

New Depreciation Expense: The New Capital Investment monthly balances less the Base Capital Investment, multiplied by the current depreciation rates. The New Capital Investment will be reduced by the replaced assets until the impact is included in the next depreciation study.

New Property Tax Expense: Calculated as the New Capital Investment balance as of the beginning of the calendar year less the Base Capital Investment multiplied by the average property tax rate from the last approved general rate case. Applicable FERC Account: FERC 408xxxx - Taxes Other Than Income

New Wyoming Wind Tax Expense: Calculated as Incremental Generation multiplied by the Wyoming Wind tax rate. Applicable FERC Account: FERC 408xxxx - Taxes Other Than Income

RTM Rate Adjustment: Rates derived to recover the RTM Deferral allocated to all applicable retail tariff rate schedules and, where appropriate, to the demand and energy rate components within each Schedule based on the applicable allocation factors and cost of service study relationships established in the most recent Commission-approved general rate case. The allocated and classified costs shall then be divided by appropriate billing determinants consistent with those used to calculate the EBA Rate Determination in Schedule 94. The RTM Adjustment shall be applicable during the RTM Rate Effective Period.

CALCULATION OF THE RTM DEFERRAL

The RTM Deferral will be calculated monthly as the sum of the Plant Revenue Requirement Deferral, the RTM NPC Benefit and the RTM PTC Benefit. Each deferral component shall be determined as follows:

(continued)

1. Plant Revenue Requirement Deferral will be calculated as:

A. Sum of the following rate case components, beginning in the first month following the in-service date for each facility, multiplied by the Company's most recently-approved pre-tax weighted average cost of capital:

i. New Capital Investment less Base Capital Investment

ii. New Accumulated Depreciation Reserve less Base Accumulated Depreciation Reserve

ii. New Accumulated Deferred Income Tax less Base Accumulated Deferred Income Tax

B. Plus the sum of the following:

i. New Operations and Maintenance Expense less Base Operations and Maintenance Expense

ii. New Depreciation Expense

iii. New Property Tax Expense

iv. New Wyoming Wind Tax Expense

2. The RTM NPC Savings will represent any incremental NPC savings associated with repowering that is not captured in the EBA, calculated as follows:

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

NPC Incremental Savings = [Incremental GenerationHLH x (Monthly Market Price HLH - Integration Costs)] + [Incremental GenerationLLH x (Monthly Market Price LLH - Integration Costs)]

RTM NPC Benefit = NPC Repowering Benefit x EBA Sharing Band

3. The RTM PTC Benefit will be calculated as the difference between the New PTC Benefit less the Base PTC Benefit. This deferral will continue to be tracked and included in the RTM until PTCs associated with wind repowering have expired and are no longer included in base rates.

Until the next general rate case, the RTM will be capped so that, after taking into account the wind repowering benefits that will flow through the EBA, it will not operate to surcharge customers.

SYMMETRICAL INTEREST: An annual interest rate of 6% simple interest (.50% per month) applied to the monthly balance in the RTM Deferral Account, consistent with the methodology described in the EBA Carrying Charge under Electric Service Schedule 94.

(continued)

MONTHLY BILL: In addition to the monthly charges contained in the Customer's applicable schedule, all monthly bills shall have the following RTM Rate Adjustment percentage applied to the monthly Power Charge and Energy Charge of the Customer's applicable electric service schedule. The collection of costs related to the RTM from customers paying contract rates shall be governed by the terms of the contract.

Schedule 1	0.00%
Schedule 2	0.00%
Schedule 3	0.00%
Schedule 6	0.00%
Schedule 6A	0.00%
Schedule 6B	0.00%
Schedule 7*	0.00%
Schedule 8	0.00%
Schedule 9	0.00%
Schedule 9A	0.00%
Schedule 10	0.00%
Schedule 11*	0.00%
Schedule 12*	0.00%
Schedule 15 (Traffic and Other Signal Systems)	0.00%
Schedule 15 (Metered Outdoor Nighttime Lighting)	0.00%
Schedule 21	0.00%
Schedule 23	0.00%
Schedule 31	**
Schedule 32	**

* The rate for Schedules 7, 11 and 12 shall be applied to the Charge per Lamp.
** The rate for Schedules 31 and 32 shall be the same as the applicable general service schedule.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

(continued)

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of June 2017, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

Utah Office of Consumer Services	
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Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations