REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Timothy J. Hemstreet

May 2020

I. INTRODUCTION AND QUALIFICATIONS

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 1800, Portland, Oregon 97232. My title is Managing Director of Renewable Energy Development for PacifiCorp. I am testifying for PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company").

Q. Briefly describe your education and professional 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 PacifiCorp in 2004, I held positions in engineering consulting at CH2M HILL (now Jacobs Engineering, Inc.) and environmental compliance at RR Donnelley Norwest, Inc. Since joining PacifiCorp, I have held positions in environmental policy and compliance, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed a role in renewable energy development, focusing on PacifiCorp's wind repowering effort, and assumed my current role in June 2019, in which I oversee the development of renewable energy resources that enhance and complement PacifiCorp's existing renewable energy resource portfolio.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously sponsored testimony in California, Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is two-fold. First, I provide an update on the construction progress and expenditures for two components of the Company's energy resource strategy, Energy Vision 2020. These two components include repowering the existing Company-owned wind fleet ("Repowering Projects") and constructing new wind facilities ("New Wind Projects"). I will refer to the Repowering Projects and New Wind Projects collectively as the "Energy Vision 2020 Projects." The Public Service Commission of Utah ("Commission") approved the New Wind Projects in Docket No. 17-035-40, along with a new transmission line and transmission network upgrades, which are discussed in the direct testimony of Mr. Richard Vail.[1] The Commission approved the Repowering Projects in Docket No. 17-035-39.[2]

In my testimony and exhibits, I provide an update on the construction status and expenditures for the New Wind Projects and Repowering Projects, demonstrate that the Company is prudently managing the construction projects, and confirm that they are on schedule to be placed in service by the end of 2020 to achieve the full value of the federal production tax credits ("PTCs"). The Company's costs as filed in this case for the New Wind Projects and Repowering Projects are very close to the project costs approved by the Commission. My testimony demonstrates the reasonableness of the increases in the individual projects over the approved costs. Further, my testimony demonstrates that the Company is prudently managing the New Wind Projects and

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[1] *Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40, Order dated June 22, 2018 (June 23, 2017).
[2] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities,* Docket No. 17-035-39, Report and Order dated May 25, 2018 at 26-27 (June 23, 2017).

Repowering Projects and the total investment should be included in the Company's revenue requirement in this case.[3]

Second, I demonstrate that PacifiCorp's upgrades to repower the Leaning Juniper and Foote Creek I wind facilities—which were not subject to the Commission's prior order on repowering —are prudent and in the public interest.[4] My testimony provides the following information:

- The scope of the Foote Creek I and Leaning Juniper repowering projects;
- The financial benefits for customers of repowering resulting from the qualification for federal PTCs;
- The increased energy benefits following repowering;
- The reduced ongoing operating costs following repowering;
- The extension of the wind facility asset life after repowering;
- Project implementation status and construction schedule; and
- The disposition of removed equipment.

My testimony demonstrates that the Company's decision to repower the Leaning Juniper and Foote Creek I facilities is reasonable and prudent, and should be

[3] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Docket No. 17-035-39, Report and Order dated May 25, 2018 at 25 (June 23, 2017). The Commission did not approve the Company's proposed Resource Tracking Mechanism and stated that the Company could effectively seek recovery of Repowering Project costs and benefits through available ratemaking mechanisms such as general rate cases, requests for deferred accounting treatment, and/or the Energy Balancing Account. The Company is requesting to include the cost of these projects along with the costs of repowering Leaning Juniper and Foote Creek I within the revenue requirement of this rate case.

[4] The 11 wind facilities approved for repowering from Docket No. 17-035-39 are Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, Dunlap I, Marengo I, Marengo II, and Goodnoe Hills and will be referred to collectively as the "Wind Repowering Project." Leaning Juniper was not pre-approved by the Commission in Docket No. 17-035-39, although the Commission expressly stated that the Company may still pursue the Leaning Juniper repowering project and seek cost recovery through a standard prudence review in a future general rate case, and that its order in Docket No. 17-035-39 should not pre-judge this issue in any way. The Company is demonstrating that the benefits to repower this facility are prudent and in the public interest within this rate case.

included in the Company's revenue requirement in this case.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. The costs incurred for the acquisition and construction of the New Wind Projects are reasonable, align closely to the costs approved in the Commission's Order in Docket No. 17-035-40, and the construction projects have been prudently managed and remain on schedule for completion by the end of 2020. Similarly, the construction costs for the Repowering Projects are generally less than the costs approved in the Commission's Order in Docket No. 17-035-39. Further, through its wind repowering efforts, PacifiCorp is leveraging past investments in its wind fleet and enhancing the future value of these resources for the benefit of its customers. The Company's repowering efforts now include all of its owned wind resources, including the Leaning Juniper and Foote Creek I facilities that were not subject to the Commission's prior order related to repowering. Foote Creek I is the oldest resource in the Company's wind fleet. By taking advantage of the unique opportunity to repower these facilities, the Company is able to deliver its customers efficiency and reliability improvements in wind generation technology, and a wind fleet that is returned to like-new condition, all while enhancing performance, reducing ongoing maintenance expenditures, and reducing customer costs.

Repowering incorporates recent technical advances that allow for installation of longer blades and nacelles with higher capacity generators, resulting in 814 additional gigawatt-hours ("GWh") of low-cost energy for customers annually, or an increase of 27 percent across the entire wind fleet. In addition to this significant increase of energy, repowering 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, the Commission should establish rates that will allow the Company to recover the costs for wind repowering that were approved in Docket No. 17-035-39. Further, the Commission should approve as prudent the investments in, and allow cost recovery for, the repowering of the Leaning Juniper and Foote Creek I wind facilities. Since the time of its order in Docket No. 17-035-39, where the Commission declined to approve the Leaning Juniper Repowering Project, improved cost and performance rendered the customer benefits from repowering this facility comparable to the benefits of the other projects that were approved in that proceeding. With respect to Foote Creek I, the Company proceeded with that project after it received approval from the Wyoming Public Service Commission for a certificate of public convenience and necessity ("CPCN") to repower the facility in 2019 and after finalizing necessary commercial arrangements.

IV. ENERGY VISION 2020 NEW WIND PROJECT OVERVIEW AND CONSTRUCTION STATUS

Q. Please provide a brief overview of the projects that are included in Energy Vision 2020.

A. As I explain above, the Energy Vision 2020 Projects consist of New Wind and Repowering Projects, along with new transmission projects addressed by Mr. Vail. In Docket No. 17-035-40, the Company received resource approvals for the New Wind Projects, consisting of the following:

- Ekola Flats Wind Project - a nominal 250 megawatt ("MW") wind facility located in Carbon County, Wyoming and associated infrastructure;
- TB Flats I and II Wind Project - a nominal 500 MW wind facility located in Carbon and Albany County, Wyoming and associated infrastructure; and
- Cedar Springs Wind Project - a nominal 400 MW wind facility located in Converse County, Wyoming and associated infrastructure, of which 200 MW (Cedar Springs II) will be owned and operated by the Company and 200 MW (Cedar Springs I) delivered to the Company under a power purchase agreement ("PPA").

Q. Did the Company seek approval from the Commission in advance of proceeding with the New Wind Projects?

A. Yes. On June 30, 2017, the Company sought approval for the New Wind Projects under Utah's Energy Resource Procurement Act ("the Act"), Chapter 17 of Utah Code Ann. Title 54. In its application that initiated Docket No. 17-035-40, the Company sought approval of a significant resource decision under Utah Code Ann. § 54-17-302 for new wind facilities and under Utah Code Ann. § 54-17-402 for new transmission facilities. In support of the application, the Company filed extensive testimony and economic analysis to demonstrate that the resource decisions were in the public interest and otherwise met the statutory requirements of the Act. The Company also included detailed, project-by-project cost estimates.

Q. Was approval of the projects and their completion time sensitive?

A. Yes. The time-sensitive nature of the New Wind projects, and related transmission projects discussed by Mr. Vail, is primarily driven by the pending phase-out of federal

PTCs for new wind resources and the time period involved to construct a major transmission line. In Internal Revenue Code section 45, the Internal Revenue Service ("IRS") provides for PTCs at the 2019 full rate of 2.5 cents per kilowatt-hour of electrical energy production by a wind facility. The PTCs are available for a 10-year period that begins when the facility is placed in service. The Protecting Americans from Tax Hikes Act of 2015 (the "PATH Act") extended the availability of the PTCs for wind facilities under construction before January 1, 2020. The PATH Act extension, however, also provides for a phase-out of the PTCs. Wind facilities that began construction before January 1, 2017, per IRS rules, will realize the full PTC credit, which is the case for the Energy Vision 2020 wind projects. If a wind facility began construction in 2017, the PTCs were reduced by 20 percent. The PTCs were reduced by 40 percent if construction began in 2018, and by 60 percent if construction began in 2019. Under the PATH Act, PTCs are not available for wind facilities that began construction after December 31, 2019.[5]

The facilities must be placed into commercial operation by the end of the fourth calendar year following the year in which construction began or otherwise meet specific IRS requirements for demonstrating the "continuity requirement" throughout the implementation timeline. To ensure customers receive the full value of PTCs, the new wind facilities included in Energy Vision 2020 must have begun construction before January 1, 2017, and, barring any changes to the law or qualification under other IRS guidance, must be placed in service by year-end 2020.

[5] On December 20, 2019, the Taxpayer Certainty and Disaster Tax Relief Act of 2019 ("2019 Tax Act") was signed into law, extending the PTC for wind energy projects that begin construction during 2020 at a rate of 60 percent. However, the 2019 Tax Act does not impact the Energy Vision 2020 Projects.

Q. Did the Commission approve the Company's request for resource approval in Docket No. 17-035-40?

A. Yes. On June 22, 2018, the Commission issued its Order in Docket No. 17-035-40 ("New Wind and Transmission Order") approving the Company's request for approval of the resource decisions that comprise the New Wind Projects and the transmission projects addressed in the testimony of Mr. Vail.

Q. In approving the New Wind Projects in Docket No. 17-035-40, did the Commission find that they were in the public interest?

A. Yes. Under Utah Code Ann. § 54-17-302 (3) and § 54-17-402(3), the Commission must determine that a resource decision is in the public interest taking into consideration the same six factors listed in each statute. These are: (i) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers, (ii) long- and short-term impacts, (iii) risk, (iv) reliability, (v) financial impacts on the utility, and (vi) other factors the Commission finds relevant.

The Commission determined based on a totality of factors that the New Wind and transmission projects were in the public interest.[6] The Commission found that the Company acquired the wind facilities through a robust solicitation process;[7] the Company's economic analysis was thorough and extensive and shows long-term benefits for customers;[8] the risk of forgoing the opportunity to capture $1.2 billion in PTC benefits is greater than the risk of proceeding;[9] and the availability of PTCs to

[6] *Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40, Order dated June 22, 2018 at 32 (June 23, 2017).
[7] *Id.* at 17.
[8] *Id*. at 22, 26.
[9] *Id*. at 27, 29.

subsidize the fulfillment of existing capacity needs strongly favors a public interest finding.[10]

Q. Under the Act, does the Commission include findings as to the total projected costs for an approved resource for purposes of later cost recovery?

A. Yes. Under Utah Code Ann. § 54-17-302 (6) and § 54-17-402(7), the Commission must include findings on the approved project costs for a resource. Under Utah Code Ann. § 54-17-303 and § 54-17-403, the Commission must allow cost recovery up to the projected amounts in the approval order, subject to two exceptions: (1) if the Commission finds the utility was imprudent based on new information or changed circumstances occurring after the approval order; or (2) the Commission finds that the utility misrepresented or concealed material information in the approval process.

Q. Did the Commission make findings as to the projected costs for the New Wind and Transmission Order?

A. Yes. The Commission made findings regarding the approved costs for each component of the New Wind Projects.[11] The Commission approved $1.189 billion in projected capital costs for the New Wind Projects. On an individual project basis, the Commission approved the costs as set forth in Confidential Exhibit RMP__(TJH-1).

Q. Under the Act, are amounts in excess of approved resource costs subject to Commission review?

A. Yes. Under Utah Code Ann. § 54-17-303(1)(c) and § 54-17-403(1)(b), any increases from projected costs specified in the Commission's approval order are subject to Commission review in a rate proceeding.

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[10] *Id.* at 32.

[11] *Id.* at 37.

Q. Since the New Wind and Transmission Order, have there been any adverse changes in circumstances that materially affect the scope or economics of the New Wind Projects and the Repowering Projects?

A. No. Utah Code Ann. § 54-17-304 and § 54-17-404 allow a utility to seek an order to proceed from the Commission in the event of change of circumstances, but, to date, there are no material changes in circumstances necessitating such a filing in this case. As discussed below, an issue did arise related to U.S. tariff impacts and other unfavorable market conditions, which negatively impacted previously established wind turbine generator ("WTG") equipment supply pricing. The Company was able to manage this issue, however, in a way that minimized the negative impact on customer net benefits.

Q. Have there been any changes to the Company's projected costs for the New Wind Projects from those approved in the Commission's Order?

A. Yes. On a total basis, the Company's costs as filed in this case are $1.220 billion, an increase of approximately $30.8 million or 2.6 percent over the approved New Wind Project costs. The project costs and variance from Commission-approved levels are set forth in Confidential Exhibit RMP__(TJH-1).

Q. Is the Company seeking recovery for the costs in excess of the approved project costs in this case?

A. Yes. These costs increases are relatively small and do not materially change the net benefits associated with the New Wind Projects. An update on the status of each project component follows below, along with an explanation of the cost increases and why they are reasonable.

Q. Before proceeding, did the Company obtain other state regulatory approvals for the New Wind Projects?

A. Yes. To capture the substantial customer benefits resulting from this time-limited opportunity and in accordance with applicable state regulatory statutes, Rocky Mountain Power received CPCNs from the Wyoming Public Service Commission and the Idaho Public Utilities Commission.[12]

Q. What is the current construction status of the TB Flats I and II wind facilities?

A. For the TB Flats I and II wind facilities, 116 of 132 WTG foundations have been constructed; WTG access roads are complete; foundations for both collector substations are complete; structural steel erection is approximately 55 percent and 68 percent complete at the TB Flats I and TB Flats II collector substations, respectively; underground collector cable installation is complete at the TB Flats I area and approximately 27 percent complete at the TB Flats II area; four of the five main power transformers have been delivered; and manufacturing and shipment of follow-on WTGs continues in support of component deliveries to the site.

Q. What is the current construction status of the Ekola Flats wind facility?

A. For the Ekola Flats wind facility, 20 of 63 WTG foundations have been constructed; WTG access roads are complete; foundations at the collector substation are complete; certain directional borings have been completed in support of underground collector cable installation; manufacturing, testing, and delivery of two main power transformers

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[12] *In the Matter of the Amended Application of Rocky Mountain Power for Certificates of Public Convenience and Necessity and Nontraditional Ratemaking for Wind and Transmission Facilities*, Docket No. 20000-520-EA-17 (Record No. 14781), Memorandum Opinion, Finding, and Order Approving Stipulation (Oct. 8, 2018); *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for New Wind and Transmission Facilities*, Case No. PAC-E-17-07, Order No. 34104 (July 20, 2018).

to the site is complete; and manufacturing of the follow-on WTGs continues in support of turbine component delivery to the site beginning in May 2020.

Q. Did the forecast capital costs for TB I and II and Ekola Flats increase over the costs approved in the Order because of the WTG issue?

A. Yes. The project costs included in this case are summarized in Confidential Exhibit RMP__(TJH-1). Vestas-American Wind Technology, Inc. ("Vestas") was originally competitively selected in the third quarter of 2017 as the follow-on WTG supplier for the Ekola Flats and TB Flats wind facilities. In the fall of 2018, Vestas communicated that it was unable to hold pricing for the WTGs due to: (1) steel pricing risk; (2) tariffs on Chinese goods; and (3) increased transportation costs. In response, the Company initiated a competitive market request for proposal updates with all originally shortlisted WTG suppliers beginning on November 15, 2018. The shortlisted suppliers from this update were asked to confirm their positions on WTG pricing and availability, run rate operations and maintenance ("O&M") costs, and equipment performance information in conformity with permit conditions and constraints.

Final firm price proposals were received on January 21, 2019. The Company completed an assessment of life cycle costs associated with the updated proposals. Both 2.* MW and 4.* MW[13] WTG platform options from multiple WTG suppliers were compared. Ultimately, the assessment concluded that the Ekola Flats and TB Flats initial capital cost estimates for WTG supply would exceed the estimates included in the Company's original filing. However, when considered in conjunction with updated

[13] The asterisk used in 2.* MW and 4.* MW is a common industry wildcard designation when referring to a range of available WTGs capacities within turbine design platforms of various original equipment manufacturers.

run rate O&M cost reductions included in the new proposals and remaining New Wind Project contingencies, customer benefits remained intact even with the increased capital costs. The Company compared the updated information to the originally assessed life-cycle cost and benefit information, which confirmed that the competitive market update and reassessment resulted in a slight increase in customer benefits when compared to the Company's final economic analysis (i.e., February 2018 economic analysis, as adjusted to remove the Uinta project).

WTG component deliveries for all of the new wind facilities included in the Energy Vision 2020 Projects will be underway in spring 2020.

Q. What is the current construction status of the Cedar Springs II wind facility?

A. For the Cedar Springs II wind facility, the project achieved the contractual Firm Date on November 7, 2019, which is a pre-closing date indicative of completion and transition from project development activities to field construction; detailed engineering work continues, site rough grading of the collector substation is complete, and work has begun on the transmission tie-line between the Cedar Springs II and the Cedar Springs I (NextEra PPA) collector substations.

Q. Are the costs for Cedar Springs II on track to be consistent with the costs approved in the Order?

A. Yes. Costs for Cedar Springs II included in this filing are approximately $[redacted] million, as shown in Confidential Exhibit RMP__(TJH-1). However, these costs do not include internal project management costs, AFUDC, or project contingencies — which, when included, are still not anticipated to exceed the approved costs.

Q. Have there been any material changes to the scope or overall economics of the New Wind Projects since the Company began work on them?

A. No. Project permitting and rights of way acquisition proceeded as planned for the Ekola Flats and TB Flats projects. An issue did arise related to U.S. tariff impacts and other unfavorable market conditions, which negatively impacted previously established WTG equipment supply pricing and competitive market costs for the 230 kilovolt transmission facilities. The U.S. tariff impacts on Ekola Flats and TB Flats WTG equipment required PacifiCorp to re-engage the originally shortlisted WTG suppliers for the Ekola Flats and TB Flats projects to submit updated WTG capital costs, run rate O&M costs, and equipment performance information. In Table 1 below, the Company compared the updated information to the originally assessed life-cycle cost and benefit information. This analysis demonstrated that the competitive market update and reassessment resulted in a slight increase in customer benefits when compared to the Company's February 2018 economic analysis, as adjusted to remove the Uinta project.

Table 1: Annual Revenue Requirement Present-Value Revenue Requirement Differential (PVRR(d)) through 2050 (Benefit) / Cost of the Projects ($ millions)

Price-Policy Scenario	Updated Annual Revenue Requirement PVRR(d)	Original Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	152	154
Medium Gas, Medium CO_2	(176)	(174)

Q. Is the Company confident that construction schedule risk is being prudently managed to deliver the New Wind Projects included in the Energy Vision 2020 by year-end 2020?

A. Yes. To manage construction schedule risk, the Company structured each of the new wind project contracts on a firm, date-certain, fixed-price, turnkey contract basis. Build-transfer counterparties, construction contractors and equipment suppliers are being held to key construction and delivery milestones and development of compressed schedule mitigation plans, if required. The Company also established construction contract completion dates and backstopped them with guarantees.

Q. What are the major milestones remaining before the December 2020 in-service date for the New Wind Projects?

A. Major Milestones are identified below:

Ekola Flats

- Mechanical Completion; October 3, 2020
- Substantial Completion; November 1, 2020

TB Flats I and II

- Mechanical Completion; October 17, 2020
- Substantial Completion; November 1, 2020

Cedar Springs II

- Mechanical Completion; November 15, 2020
- Substantial Completion; December 26, 2020
- Closing; December 31, 2020

V. WIND REPOWERING PROJECT OVERVIEW 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 WTG equipment that can increase a facility's generating capacity and the amount of electrical generation produced from the facility. Specifically, PacifiCorp's repowering effort involves replacing the nacelle, hub, and rotor of the WTG at all facilities, except the Foote Creek I facility, where repowering will involve replacement of the existing WTGs, including the foundations and towers. Exhibit RMP___(TJH-2) includes a depiction of a wind turbine and its various components.

Q. Which facilities have been or will be repowered?

A. PacifiCorp has or will repower the facilities known as Dunlap, Foote Creek I, Glenrock I, Glenrock III, Goodnoe Hills, High Plains, Leaning Juniper, Marengo I, Marengo II, McFadden Ridge, Rolling Hills, Seven Mile Hill I, and Seven Mile Hill II. At 11 of the 13 facilities - all facilities except for Dunlap and Foote Creek I[14] - major construction activities are complete and the repowered facilities are now in commercial operation. Site reclamation and other activities to finalize the 11 projects now in commercial operation are ongoing and final project costs will be filed with the Commission, consistent with its order in Docket No. 17-035-39, when the projects are closed.

Q. How many MW of installed wind capacity is PacifiCorp repowering?

A. PacifiCorp is repowering all of its 13 wind facilities, representing approximately 1,040 MW of installed wind capacity prior to repowering. After repowering, the capacity of the repowered facilities will increase to approximately 1,064 MW due to increased transmission interconnection capacity at the Marengo I and Marengo II facilities, and full utilization of the 41.4 MW interconnection capacity at Foote Creek I. Detailed information about the wind facilities that have been or are currently being repowered is included in Exhibit RMP___(TJH-3).

[14] Repowering will occur in 2020 for Dunlap and Foote Creek I.

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

A. The wind facilities PacifiCorp is repowering began commercial operations between 1999 and 2010. Aside from the Foote Creek I facility, the facilities in PacifiCorp's wind fleet can be economically repowered, or upgraded, with new technology that will improve their efficiency and increase their generation output, without incurring the cost to replace the existing towers, foundations, and energy collection systems, which are of sufficient design to accommodate more modern equipment now available. 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 still have a sufficient remaining useful life to economically justify the associated investment.

Q. Did the Company seek a resource decision approval from the Commission in advance of proceeding with the repowering projects?

A. Yes. On June 30, 2017, the Company filed an application requesting approval for the repowering projects under the Act, Chapter 17 of Utah Code Ann. Title 54. In its application, the Company sought approval of a resource decision under Utah Code Ann. § 54-17-402 for the repowering projects. In support of both applications, the Company filed extensive testimony and economic analysis to demonstrate that the resource decisions were in the public interest and otherwise met the statutory requirements of the Act. The Company also included detailed, project-by-project cost estimates.

Q. Did the Commission approve the Company's request for resource approvals in Docket No. 17-035-39?

A. Yes. On May 25, 2018, the Commission issued its Order in Docket No. 17-035-39 approving 11 of the 12 repowering projects, which included Dunlap, Glenrock I, Glenrock III, Goodnoe Hills, High Plains, Marengo I, Marengo II, McFadden Ridge, Rolling Hills, Seven Mile Hill I, and Seven Mile Hill II. PacifiCorp received approval for these projects subject to individual projected costs for each project. In its Order, the Commission did not approve the Company's Leaning Juniper repowering project; however, as I noted above, the Company was not barred from pursuing the project. I will discuss the budget status with respect to the approved projected costs later in my testimony.

Q. Why did the Company move forward with repowering Leaning Juniper?

A. There were two major factors that changed, which resulted in the Leaning Juniper repowering demonstrating more significant customer benefits. Following the conclusion of the proceeding in Docket No. 17-035-39, the Company was able to negotiate more favorable pricing for the Leaning Juniper repowering project and new equipment specifications resulted in slightly improved performance for the repowered project. The reduced cost and increased energy output improved the economics of repowering the facility, resulting in customer benefits similar to those obtained from the other repowering projects that were approved by the Commission. Given these favorable changes, the Company elected to pursue repowering of the Leaning Juniper project and seeks a prudence determination and cost recovery for this project through this rate case proceeding.

Q. Is repowering at Leaning Juniper now complete?

A. Yes. The repowered Leaning Juniper facility achieved commercial operation on September 13, 2019, although minor work to finalize the project continues.

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Q. How did the cost and performance of the Leaning Juniper project change as compared to the assumptions used by the Company when Leaning Juniper was proposed for repowering in Docket No. 17-035-39?

A. Anticipated costs for the project were reduced by [redacted] and the incremental generation from the project increased by approximately [redacted] megawatt-hours. The improved economics of the project are described in Mr. Rick T. Link's testimony.

Q. As you mentioned earlier, the scope of repowering at Foote Creek I is different than repowering at the Company's other wind facilities. Can you provide additional background on the Company's decision to repower Foote Creek I?

A. Foote Creek I, the Company's oldest wind facility, began commercial operation in April 1999. The facility served as a demonstration project to evaluate the feasibility of utility-scale wind energy. The facility was developed in partnership with the Eugene Water & Electric Board ("EWEB") and the Bonneville Power Administration ("BPA"). As developed, Foote Creek I was co-owned by EWEB (21.21 percent ownership) and PacifiCorp (78.79 percent ownership), with BPA taking 37 percent of the facility's output through a 25-year cost-based PPA. As the first utility-scale wind energy project in Wyoming, Foote Creek I was sited at one of the most favorable wind sites in the United States and enjoys the highest wind speeds of any of the Company's wind projects. Unlike the remainder of the facilities the Company is repowering, the Foote Creek I project is unique in that it was co-owned and also had a third-party PPA associated with the resource.

The Foote Creek I facility currently consists of 68 turbines, each with a 600-kilowatt generating capacity, a rotor diameter of 42 meters, and towers that support a

40 meter hub height. Although employing the latest technology when originally installed, the existing turbines are costly to operate and maintain relative to the Company's more modern turbines that have a much higher nameplate capacity, larger rotor diameters, and taller towers. Accordingly, the operation and maintenance costs of the Foote Creek I facility are the highest of all of the Company-owned wind resources on a per-MW basis since the maintenance requirements for these smaller turbines are similar to those of larger turbines, but the capacity of the Foote Creek I turbines is much less.

The costs associated with continued operation of the existing turbines at Foote Creek I for both the Company and EWEB would increase after the expiration of the BPA PPA in April 2024 since 37 percent of these costs would no longer be covered through the cost-based PPA. Similarly, BPA was required to take higher cost energy from the project until the PPA expired. For these reasons, PacifiCorp, EWEB, and BPA were all motivated to explore whether the existing Foote Creek I project could be unwound in order to achieve an outcome more favorable to customers as compared to continuing to operate the facility through its planned 30-year asset life. Repowering the facility presented the opportunity to realize this outcome for all customers.

Q. Please explain what repowering at the Foote Creek I wind facility involves.

A. The WTG equipment at Foote Creek I has a low generating capacity (600 kilowatts) per turbine and the towers and foundations supporting the nacelle and rotor do not have the necessary 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.

Due to the limitations of the older facility, repowering Foote Creek I requires complete removal and replacement of the old wind turbine equipment. The towers, foundations and energy collection system must be replaced with new foundations to support the larger towers and appropriately sized energy-collector circuits. Repowering the Foote Creek I facility will result in the replacement of the current 68 small-capacity wind turbines at the site with 13 modern wind turbines.

Q. What was necessary for the Company to repower the project?

A. Because of the very favorable wind conditions at the site, the Company was interested in repowering the facility so that customers could benefit from the low-cost energy that could be generated at the site with modern wind turbine equipment qualified at 100 percent of the value of the PTCs. To achieve that, however, it was necessary for the Company to acquire EWEB's ownership share of the facility and to terminate the existing PPA with BPA. The Company negotiated a PPA termination agreement with EWEB and BPA, and a purchase and sale agreement with EWEB for its interests in the facility. The termination of the PPA was negotiated to be effective upon PacifiCorp's acquisition of EWEB's interest in the project, and the closing of the purchase and sale agreement with EWEB was contingent upon the Company obtaining necessary regulatory and permitting approvals related to repowering as well as satisfactory commercial arrangements for turbine supply and construction that ensured repowering could occur.

Q. How much did the Company pay EWEB for its interests in the facility?

A. PacifiCorp paid EWEB approximately [redacted] for its interests in the facility.

Q. Did the Company incur costs to terminate the Foote Creek I PPA with BPA?

A. No. Under the termination agreement, BPA paid an early termination payment for the facility in the amount of [redacted] of which [redacted]—the Company's 78.79 percent ownership share of the facility—was paid to the Company. This payment to the Company and EWEB reflected the fact that BPA realizes savings by terminating the PPA early and replacing the power with lower cost energy resources.

Q. Were these amounts consistent with the Company's expectations?

A. Yes. These payments were consistent with the Company's economic analysis of the Foote Creek I repowering project, which is described by Mr. Link.

Q. Did the Company enter other commercial arrangements related to repowering at Foote Creek I?

A. Yes. The Company executed a turbine supply agreement with Vestas and executed a balance of plant construction contract with Thorstad Companies, Inc. Both contracts were awarded following competitive solicitation processes. When these contracts were finalized, the Company proceeded to close on the purchase of EWEB's interest in the project and terminate the PPA. The Company also purchased the wind energy lease rights for the Foote Creek I facility.

Q. Why did the Company purchase the wind energy lease rights for Foote Creek I?

A. The Company was operating the Foote Creek I facility under land rights that were subleased from Chandar Energy Land Associates, Inc. ("CELA"), which held the master wind energy lease rights with the ultimate property owners upon whose land the Foote Creek I turbines are located. Taking into account the high-value wind energy resource at the site, the wind energy production-based lease payments owed to CELA under the sublease were still more costly than what the Company pays for similar production-based wind energy leases. The Company was able to negotiate the purchase of the master wind energy leases from CELA at a cost that improved the economics of the Foote Creek I repowering project relative to continuing to operate under the existing sublease. Additionally, the master wind energy lease rights can be renewed for a total term of up to 99 years, providing potential future customer benefits beyond the asset life of the repowered Foote Creek I facility.

Q. Were there unique permitting requirements related to Foote Creek I as compared to the other repowering projects?

A. Yes. It was necessary for the Company to obtain approval of a new CPCN from the Wyoming Public Service Commission related to repowering the facility and a new Conditional Use Permit from Carbon County, Wyoming. The Company also had to obtain concurrence from the Bureau of Land Management ("BLM") that repowering was consistent with the existing right of way grant from BLM for the facility, and the Company worked with the U.S. Fish and Wildlife Service to review the locations of the new turbines on the existing project footprint to evaluate and minimize potential avian impacts associated with the new turbine layout.

Q. When did the Company finally approve repowering the Foote Creek I facility?

A. The Company approved repowering the facility on June 25, 2019. The Company then closed on the purchase of EWEB's interest in the facility on July 24, 2019, after commercial arrangements to repower the facility were finalized. Following approval of the repowering project, the Company was able to negotiate the purchase of the master wind leases and incorporated this change into the project scope. The Company subsequently closed on the purchase of the master wind energy lease rights from CELA on August 8, 2019.

Q. What repowering costs are the Company seeking to recover in this filing?

A. The Company is seeking to recover costs associated with the facilities previously determined by the Commission to be prudent to repower, as well as the costs to repower the Leaning Juniper facility and the costs to acquire the wind energy lease rights and repower the Foote Creek I wind facility.

Q. What benefits will customers realize from repowering Leaning Juniper and Foote Creek I?

A. Repowering these facilities re-qualifies them for PTCs, which are benefits that are passed through to customers. Additionally, repowering increases the amount of zero fuel cost energy produced from the repowered facilities, as shown in Confidential Exhibit RMP___(TJH-3). Further, by replacing older WTG equipment, which is subject to more failure and maintenance issues than newer equipment, repowering will reduce PacifiCorp's ongoing operating costs. Finally, repowering the wind facilities with new WTG equipment will extend the useful lives of the facilities by up to 21 years, creating substantial energy and capacity benefits for customers in the future when this wind facility would otherwise have been retired from service.

VI. REQUALIFICATION FOR PTCS

Q. How do the Repowering Projects qualify for the PTC extension enacted in 2015?

A. The IRS guidance, which I discussed above in relation to the New Wind Projects, 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 were 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. The IRS guidance on the four calendar year "safe harbor" with respect to the continuous-efforts standard that I discussed in relation to the New Wind Projects also applies to the Repowering Projects. Thus, as with the New Wind Projects, the Repowering Projects must be in service no later than December 31, 2020, to satisfy the continuous-efforts safe-harbor provisions. If the Repowering Projects are not placed in service by December 31, 2020, the projects must satisfy the potentially more challenging IRS requirements that continuous-efforts were expended to repower the facilities.

Q. Is the full value of the PTC for the Repowering Projects the same as those for the New Wind Projects?

A. Yes. During the 10-year period after the wind facility begins commercial operation, the Repowering Projects will receive the same 2.5 cents per kilowatt-hour or $25 per megawatt-hour, adjusted annually for inflation as the New Wind Projects.

Q. Do the Leaning Juniper and Foote Creek I repowering projects 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, PacifiCorp executed safe harbor equipment purchases with General

Electric International, Inc. and Vestas 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. For the Foote Creek I facility, PacifiCorp will use safe harbor equipment obtained from Berkshire Hathaway Energy Renewables, a Berkshire Hathaway Energy subsidiary, which made safe harbor equipment purchases from Vestas in December 2016 that can be used to qualify the Foote Creek I project for 100 percent of the PTC value.

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

A. On May 5, 2016, the IRS issued Notice 2016-31, which provides guidance on various aspects of qualifying for the PTCs and whether new tax credits can be claimed when wind turbines are repowered or retrofitted. Notice 2016-31 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. Does the Leaning Juniper facility pass this 80/20 test?

A. Yes. The Leaning Juniper project passes this 80/20 test, similar to PacifiCorp’s other repowering projects.

Q. Is the Foote Creek I facility subject to this 80/20 test?

A. No. The Foote Creek I facility will be repowered without using any retained wind turbine components. The tower and foundations of the existing turbines at the site will not be reused, unlike at PacifiCorp's other repowering projects. In other words, the applicable repowering costs at Foote Creek I, on a per-turbine basis, will equal 100 percent at this facility.

Q. Have recent changes to federal tax laws impacted the ability to qualify the Company's repowered facilities for PTCs?

A. No. Neither the Tax Cuts and Jobs Act, enacted into law in December 2017, nor the Tax Extender and Disaster Relief Act of 2019 change the qualification requirements that allow all of the Company's repowered wind facilities to receive the full value of PTCs.

VII. INCREASED ENERGY BENEFITS FOLLOWING REPOWERING

Q. Once repowered, how do the energy benefits of the Leaning Juniper and Foote Creek I wind facilities increase?

A. At Leaning Juniper, repowering will involve the replacement of the existing machine heads, including the nacelle, hub and rotor, while the Foote Creek I facility will employ entirely new wind turbines with new foundations and taller towers. The new nacelles have generators with greater nameplate generating capacity than the removed equipment. As a result of repowering, the nameplate rating of the turbines at Leaning Juniper will increase from 1.5 MW to 1.6 MW. At Foote Creek I, the new turbines installed at the site will have generator nameplate ratings of 2.0 MW and 4.2 MW, replacing existing turbines with a 0.6 MW nameplate rating. Details regarding the proposed wind turbine upgrades, in-service dates, and resulting energy benefits are

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shown in Confidential Exhibit RMP___(TJH-3).

In addition to the larger generators in the repowered turbines, the new turbines also include larger blades, which will increase the rotor-swept area of the wind turbines. 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.

Finally, the Foote Creek I repowering project will result in all of the facility's output serving the Company's customers as compared to only approximately 47 percent under the earlier co-ownership and PPA structure. With the entire output of Foote Creek I directed to the Company's customers, and with the increased generation from the more efficient turbines, the amount of zero-fuel-cost energy provided to customers by the facility will increase by more than [redacted] percent.

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

A. Not necessarily. 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. PacifiCorp performs monthly monitoring at all of its wind facilities and reports all findings to state wildlife agencies and the U.S. Fish and Wildlife Service. PacifiCorp 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. Are there other ways that the Company has worked to minimize avian impacts?

A. Yes. At the Foote Creek I facility, the significant reduction in the number of turbines possible with site repowering means that less of the overall project site area will be covered by wind turbines. This has allowed the Company to adjust the layout of the wind turbines at the project site to avoid areas of higher avian use, such as the edges of Foote Creek Rim, minimizing potential avian impacts.

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

A. For Leaning Juniper, where the turbine locations and turbine hub heights are not changing, PacifiCorp worked with its consultant, Black & Veatch ("B&V"), to use the extensive data history from PacifiCorp's facilities to derive estimates of the energy production expected from repowering. This analysis used millions of data points from the operational record of the facility and incorporated additional modeled wake losses anticipated from the new equipment. 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.

Based on its analysis, PacifiCorp and B&V estimate that energy production at Leaning Juniper following repowering will increase as shown in Confidential Exhibit RMP___(TJH-3), and as further discussed below. These results reflect, as accurately as possible, the energy production that would have occurred from the repowered turbines under the same operational conditions and availability as the existing equipment. However, these repowering energy estimates may be conservative. They are based solely on the different equipment performance specifications of the newer equipment and do not account for expected improvements in operational availability of the wind facilities following repowering. Availability of the wind turbines likely will improve after repowering given the additional sensors and condition monitoring systems in the repowered turbines that should allow for improved diagnostics and implementation of preventative maintenance measures that can reduce turbine down-time. Additionally, PacifiCorp will operate the new turbines under service agreements with the turbine suppliers with performance guarantees and incentives that are likely to result in more availability and generation than PacifiCorp has achieved in the past under similar wind conditions. These contracts are discussed in more detail later in this testimony.

Q. How did the energy estimate methodology of the Foote Creek I facility differ from the methodology used at the Leaning Juniper facility?

A. At the Foote Creek I facility, B&V evaluated historical project generation and availability data from the existing Foote Creek I turbines, local and project-specific meteorological information, and the new proposed turbine layout to model the anticipated energy output of the repowered wind project, similar to the approach used by the Company to estimate the energy output from its new wind projects now under construction.

Q. Why was this approach most suitable for Foote Creek I?

A. This approach was most suitable because the turbine locations are changing at Foote Creek I, as discussed above, and also because the turbine hub heights are increasing from 40 meters to 80 meters. Due to the different location of turbines and turbine hub heights, the wind speed, turbulence intensity, and wind inflow angle experienced by the existing turbines may not be representative of what the new turbines will experience. For these reasons, wind modeling was relied upon to develop the energy estimate for Foote Creek I.

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, 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. Additionally, the new 4.2 MW capacity wind turbines have a higher cut-out wind speed than the existing turbines, meaning they can continue producing power at higher wind speeds in which the existing equipment at the site would shut down. Because the new turbines 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, allowing the facility to produce equivalent capacity with far fewer turbines. Exhibit RMP___(TJH-4) illustrates these power production advantages and compares the power curve of the existing wind turbines to that of the new wind turbines.

Q. Why was this larger equipment not 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 facilities employing entirely new wind turbines, these technology improvements mean that longer blades and additional generating capacity are 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 where the tower and foundation can be re-used, 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 repowered wind facilities are estimated to increase generation by 814 GWh per year, an increase of 27 percent.

Q. Given the higher nameplate capacity of the new turbines, has the Company been able to increase the output capacity of the wind facilities?

A. As I mentioned earlier, the Company has been able to increase the allowed generation interconnection agreement for the Marengo facilities, increasing the capacity of the Marengo facilities from a combined 210.6 MW to 234 MW. This increase in interconnection capacity allows more energy to be delivered to customers from those facilities. The Company has not pursued generation interconnection increases at the Goodnoe Hills and Leaning Juniper facilities given transmission constraints and costs for those facilities, which are interconnected to BPA’s transmission system. For the

Wyoming facilities, transmission studies are still ongoing related to the Company's requests to increase the generation interconnection limits for those facilities. Thus, no increase in interconnection capacity for the Wyoming facilities has been realized, and the Company has not pursued necessary improvements to the energy collector systems at those projects that would be necessary if additional interconnection capacity was available.

VIII. REDUCED ONGOING OPERATIONAL COSTS FOLLOWING REPOWERING

Q. Aside from increased generation and the associated PTC benefits, what other benefits will be realized with the Leaning Juniper and Foote Creek I repowering projects?

A. The repowering projects will lower the ongoing capital costs of operating the existing wind facilities. PacifiCorp'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 turbine components currently in service.

The repowering projects will also result in more certainty related to ongoing O&M costs of the facility. PacifiCorp will operate the repowered facilities under full service agreements with the turbine equipment suppliers who will be responsible for operating and maintaining the new turbines for a fixed cost while attaining a guaranteed availability of the turbines. Under these agreements, failure to meet the guaranteed availability, if not the result of an excusable event defined in the contract, will result in the payment of liquidated damages to the Company. Customers will benefit by having operation and maintenance costs fixed for the term of the agreement. Thus, there is greater cost certainty related to the run-rate capital expenditures and operation and maintenance costs.

Q. Does the new equipment address any other operational issues?

A. Yes. In addition to the reduced capital run rate of the new equipment in the early years after installation, repowering avoided costs from replacing certain models of gearboxes found at the Leaning Juniper project. These gearboxes, which were original equipment supplied by the turbine manufacturer, were experiencing high failure rates compared to other models of gearboxes installed elsewhere within the wind fleet. Consequently, PacifiCorp experienced increased capital costs in recent years to address the gearbox failures, and these models were 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." This means that 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 did PacifiCorp expect at Leaning Juniper if there was no repowering?

A. There were 28 of these gearbox models at Leaning Juniper before repowering, and

PacifiCorp anticipated that all of these remaining gearboxes would have failed and required replacement by 2031.

Q. Are there similar issues with gearboxes at the Foote Creek I facility?

A. Yes. Gearboxes at the Foote Creek I facility have also experienced high failure rates relative to other gearboxes in the wind fleet. However, the impact to the Company of these failures has been mitigated by an agreement that was set to expire in 2024, at which point the cost of addressing failed gearboxes would be borne entirely by the Company and EWEB. Given the short remaining life of the project in 2024, with just 5 years of operational life remaining, turbines that experienced a failed gearbox after that time could not be economically returned to service given the limited remaining generation anticipated from the existing turbines and the estimated cost to replace a failed gearbox. Thus, repowering also addresses the likelihood of diminished generation from the Foote Creek I facility after 2024.

Q. What is the current asset life of the Leaning Juniper and Foote Creek I wind facilities?

A. All of the Company's existing wind facilities are currently being depreciated assuming a 30-year asset life. Given the 1999 commercial operation date of Foote Creek I, the depreciable life approved by the Commission for Foote Creek I is 2029. Similarly, the 2006 commercial operation date for Leaning Juniper results in an anticipated 2036 retirement of the facility had it not been repowered.[15] In anticipation of repowering the facilities the Company proposed in the 2018 depreciation study, Docket No. 18-035-

[15] *In the Matter of the Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2014*, Docket No. 13-035-02, Order Confirming Bench Ruling Approving Stipulation on Depreciation Rate Changes (Nov. 7, 2013).

36, a new 30-year depreciable life following repowering that would extend the asset life of Foote Creek I by 21 years to 2050 and extend the asset life for Leaning Juniper by 13 years to 2049, similar to the other facilities that have undergone repowering.

PROJECT PERMITTING, CONSTRUCTION AND BUDGET STATUS

Q. What is the status of permitting related to the Foote Creek I repowering project?

A. PacifiCorp received approval from the Federal Aviation Administration for the new turbine locations in April 2018, indicating the new turbines location and heights would not pose a hazard to air navigation. Carbon County, Wyoming issued a new Conditional Use Permit for the repowered project in April 2019. The BLM, upon whose land approximately half of the turbines at the site are located, accepted the Company's revised plan of development for the project in June 2019, reflecting the repowered project.

Q. What is the status of contracting related to the Foote Creek I repowering project?

A. In July 2019, PacifiCorp executed contracts with Vestas for turbine supply and service and maintenance of the new turbines that will be installed at the site and a construction contract with Thorstad Companies, Inc. for construction of the project.

Q. Has construction commenced on the Foote Creek I repowering project?

A. Yes. Initial site work began in the fall of 2019 with the installation of construction trailers, foundation excavation, and material deliveries. Site work was halted for the winter and resumed in early March 2020 when weather conditions were more favorable for construction. Foundation excavation has been completed and turbine component manufacturing is currently underway, with turbine deliveries anticipated to begin in July 2020.

Q. When does the Company anticipate that Foote Creek I will enter commercial operation?

A. Commercial operation of the repowered Foote Creek I facility is anticipated to occur by December 1, 2020.

Q. What is the construction status of the Wind Repowering Projects that were approved by the Commission in Docket No. 17-035-39?

A. Except for Dunlap, which was always anticipated to be repowered in 2020, major construction activities have been completed at all of the Company's repowering projects that were approved by the Commission in Docket No. 17-035-39, and the projects have all achieved commercial operation. Minor activities to finish the projects remain, including completion of punch list items, site reclamation, minor electrical work, control system completion, and final operational programming.

Q. Did the Commission make findings as to the projected costs in Docket No. 17-035-39?

A. Yes. Under Utah Code Ann. § 54-17-402(7), the Commission must include findings on the approved project costs for a resource. Under Utah Code Ann. § 54-17-403, the Commission must allow cost recovery up to the projected amounts in the approval order, subject to two exceptions: (1) if the Commission finds the utility was imprudent based on new information or changed circumstances occurring after the approval order; or (2) the Commission finds that the utility misrepresented or concealed material information in the approval process.

In its Order in Docket No. 17-035-39, the Commission made findings regarding the approved costs for each project comprising the repowered facilities.[16] On a total basis, the Commission approved $978.8 million in projected capital costs. On an individual project basis, the Commission approved the costs as set forth in Confidential Exhibit RMP__(TJH-1SD), page 1 of 3, column 8.

Q. Under the Act, are amounts in excess of approved resource costs subject to Commission review?

A. Yes. Under Utah Code Ann. § 54-17-403(1)(b), any increases from projected costs specified in the Commission's approval order are subject to Commission review in a rate proceeding.

Q. What is the budget status for the repowered facilities that were approved by the Commission in Docket No. 17-035-39?

A. While major construction activities at Dunlap are still yet to occur this summer, and minor project-related activities continue at the remaining sites, the Company has diligently managed the repowering effort and the overall cost of repowering the facilities. Overall, capital costs for the eleven repowering projects pre-approved in Docket No. 17-035-39 are estimated to be less than the total amount approved. On a project-by-project basis, nine of the 11 projects are expected to be completed at costs that are less than the capital costs pre-approved by the Commission. Please refer to Confidential Exhibit RMP__(TJH-1) for the repowering project costs that were pre-approved by the Commission and the Company's capital costs by project as filed in this proceeding.

[16] Docket No. 17-035-39, Report and Order at 26.

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Q. What two projects are anticipated to have capital costs that exceed amounts pre-approved by the Commission?

A. Capital costs at the [redacted] projects are currently anticipated to exceed the pre-approved amounts. For the [redacted] Overall, the eleven repowering projects, collectively, are forecast to be completed below the total amount presented in Docket No. 17-035-39.

Q. What are the reasons for the cost increases at those two facilities?

A. At the [redacted]

[redacted] conditions were also identified that had to be addressed.

Q. What has driven costs [redacted] to exceed the amount that was pre-approved by the Commission?

A. PacifiCorp [redacted] which has increased estimated project costs above the pre-approved amounts.

Q. What is the budget status for the Leaning Juniper and Foote Creek I facilities?

A. Leaning Juniper's final project costs are less than what was anticipated when the Company determined to move forward with the revised project, which further improves the economics of the project relative to what was anticipated when the Company decided to move forward with the project, and relative to the economics of the project as it was reviewed in Docket No. 17-035-39. I expect that the Foote Creek I project, which will be completed in December of this year, will be delivered at or near the costs anticipated by the Company and included in this case.

Q. Has the COVID-19 public health emergency had a material impact on the Company's construction schedule or costs for the Repowering Projects or the New Wind Projects?

A. First and foremost, the Company is working closely with its contractors and suppliers to ensure that work on the projects proceeds in a manner that protects the safety of the people working on the projects and the local public where the projects are located. For the 11 repowering projects that have reached commercial operation, I do not anticipate any material impact of the COVID-19 public health emergency on remaining construction efforts or the schedule to complete the very limited remaining work necessary at those projects. At the Dunlap project, all major wind turbine components were delivered to the project by January 2020, before the COVID-19 public health emergency began. Thus, the Dunlap project is not facing equipment supply impacts and the project will be employing construction staff already operating safely under contagious disease protection protocols. Therefore, I do not anticipate construction schedule or costs risks at this time at the Dunlap project, though the impacts of the public health emergency are obviously dynamic and can change rapidly as everyone has observed over the last several months.

At the Foote Creek I repowering project, work is proceeding at the project under COVID-19 mitigation plans to address worker safety. Impacts of the public health emergency have the potential to impact equipment supply and transport logistics, but so far no impacts are confirmed, although contractors involved in the project have issued force majeure notices of potential, but yet unknown impacts and equipment delivery delays may occur.

Potential impacts on the Company's New Wind Projects from the COVID-19 public health emergency continue to emerge. The Company has received general force majeure notices of potential COVID-19 impacts from a majority of the contractors on its New Wind Projects indicating potential delays. Turbine deliveries to the TB Flats I and II project, which began in April 2020, are likely to experience delays, and impacts to deliveries of follow-on wind turbine equipment at the Ekola project may occur. However, at this time the Company is not aware of confirmed project schedule impacts that will impact the ability to complete the projects by year-end 2020. The Company continues to work closely with its contractors and equipment suppliers to ensure that the people working on the projects and the public in general are protected by complying with all governmental requirements, orders and directives, and will work to mitigate potential impacts to construction schedules.

Given the evolving nature of the best guidance on how to protect public health and promote worker safety in these conditions, there could be impacts to productivity on both the Repowering Projects and New Wind Projects that could impact construction schedules or result in additional cost — but those impacts are not known at this time. The Company and its contractors and suppliers remain committed to deliver the New Wind Projects by year-end 2020. The Company will provide an update with respect to any impacts related to the COVID-19 public health emergency in rebuttal testimony.

IX. DISPOSITION OF REPLACED EQUIPMENT

Q. What is PacifiCorp planning to do with the existing equipment that will be removed from the repowered facilities?

A. PacifiCorp issued a request for proposals related to the disposition of the existing equipment in which the Company sought proposals for the purchase or removal of the equipment that will be replaced as part of repowering the entirety of its wind fleet. In general, proposals received from this solicitation were not favorable as compared to the equipment removal proposals offered by the construction contractors that are installing the new equipment.

Q. Did PacifiCorp make efforts to maximize the salvage value of the equipment being replaced at the repowered facilities?

A. Yes. Unfortunately, a significant number of turbines of all makes and models are currently being repowered by PacifiCorp and other companies. This will likely continue to be the case before the sunset of the PTCs available for wind energy projects in 2024. As a result, there is very little market for used turbines and the salvage value of the equipment is very low given the large number of repowered turbines and associated spare parts that have become available as a result of the significant repowering effort that the wind industry is now undertaking. While some individual turbine component sales have resulted from PacifiCorp's efforts to obtain the highest salvage value from the removed equipment at other repowered projects, the lowest cost alternative for the disposition of the old equipment is to allow the construction contractors to retain the equipment so the scrap value offsets their equipment removal, handling, and transportation costs. That is also the case at Leaning Juniper and Foote

Creek I, where no anticipated equipment sales are anticipated at this time. Given the relative inefficiency of the replaced equipment compared to new equipment, it does not make economic sense to redeploy the replaced equipment at other potential wind sites.

Q. Does the Company's inability to achieve a salvage value for the replaced equipment impact the Company's economic analysis of the Leaning Juniper or Foote Creek I repowering projects?

A. No. PacifiCorp did not assume any salvage value for the replaced equipment in its economic analysis of these projects. Thus, project economics are not impacted by the fact that very little of the old equipment will ultimately be re-sold by the Company when it is removed.

X. CONCLUSION

Q. Please summarize your recommendations.

A. The Company has prudently managed the implementation and costs of the New Wind Projects. Consistent with the Commission's resource approval Order in Docket No. 17-035-40, the Commission should now allow full recovery of the approved costs. The Commission should also allow recovery of the additional costs as filed, which are reasonable and do not materially impact the net benefits associated with the New Wind Projects. Understanding these projects are currently in construction, the Company will update the costs of the New Wind Projects to reflect the latest forecasted project costs in rebuttal testimony.

The Company's wind repowering efforts leverage past investments in PacifiCorp's wind fleet to enhance the future value of these resources for the benefit of its customers. By taking advantage of the unique opportunity to repower these facilities, the Company is able to deliver its customers efficiency and reliability improvements in wind generation technology, extend their life by returning the wind fleet to like-new condition, all while enhancing performance, reducing ongoing maintenance expenditures, and re-qualifying these facilities for PTCs — all of which reduces customers' rates. The Company has prudently managed the implementation and costs of the Repowering Projects and I recommend that the Commission allow the Company to recover the costs incurred and allow recovery for the incurred costs in excess of the pre-approved amounts for the Dunlap and Goodnoe Hills repowering projects because the additional costs were necessary and prudently managed by the Company and the projects continue to be beneficial to customers overall. Finally, I recommend that the Commission determine that the Leaning Juniper and Foote Creek I repowering projects provide benefits to Utah customers and are therefore prudent and in the public interest, and that the Company be allowed to include the revenue requirement of these projects in rates approved in this case.

Q. Does this conclude your direct testimony?

A. Yes.

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Rocky Mountain Power
Exhibit RMP___(TJH-1)
Docket No. 20-035-04
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

EV2020 Wind Capital Cost

May 2020

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

Rocky Mountain Power
Exhibit RMP___(TJH-2)
Docket No. 20-035-04
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

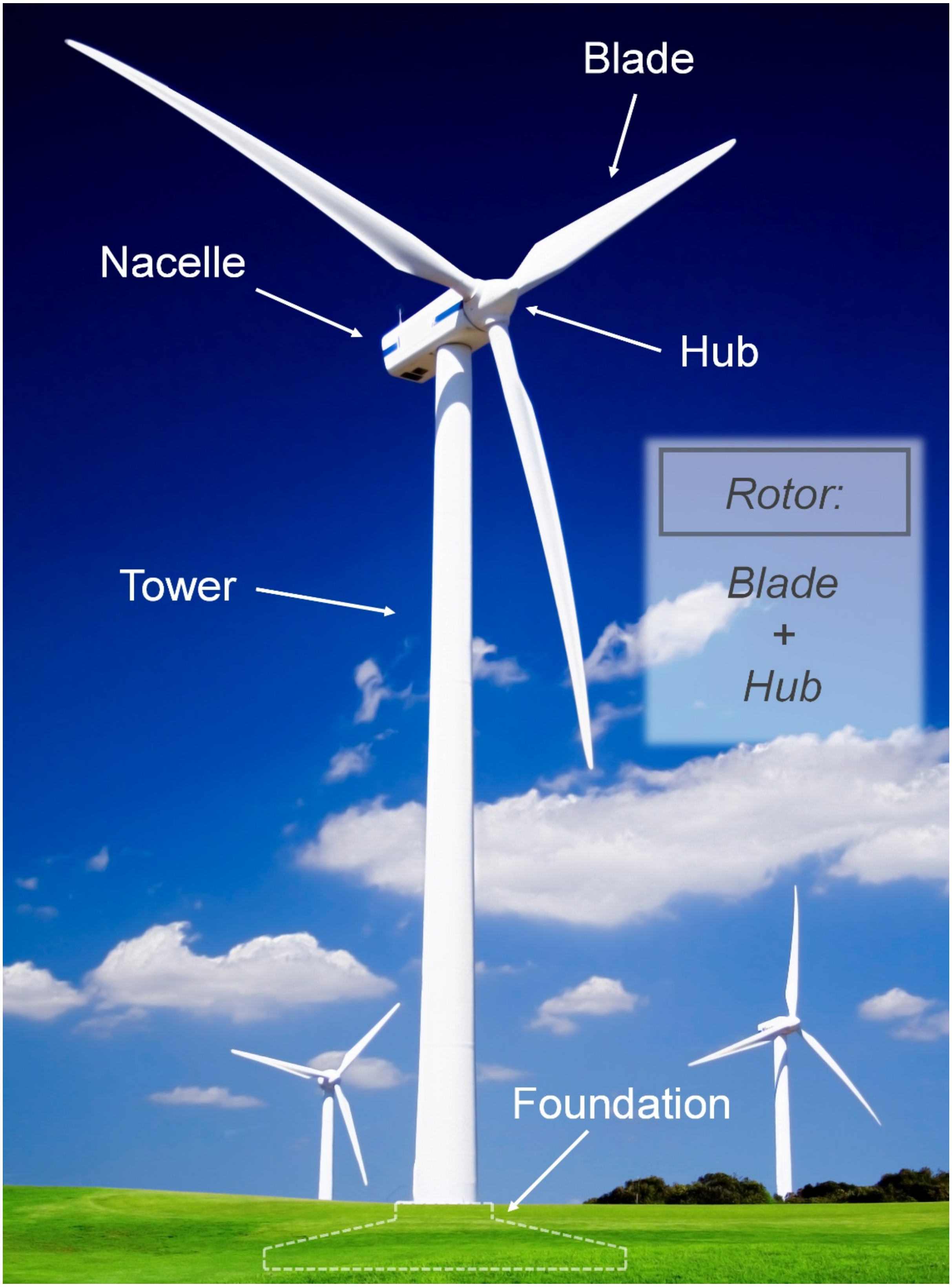
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Major Components of a Wind Generator

May 2020

Major Components of a Wind Turbine Generator



REDACTED
Rocky Mountain Power
Exhibit RMP___(TJH-3)
Docket No. 20-035-04
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 Project Details and In-Service Dates

May 2020

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

Rocky Mountain Power
Exhibit RMP___(TJH-4)
Docket No. 20-035-04
Witness: Timothy J. Hemstreet

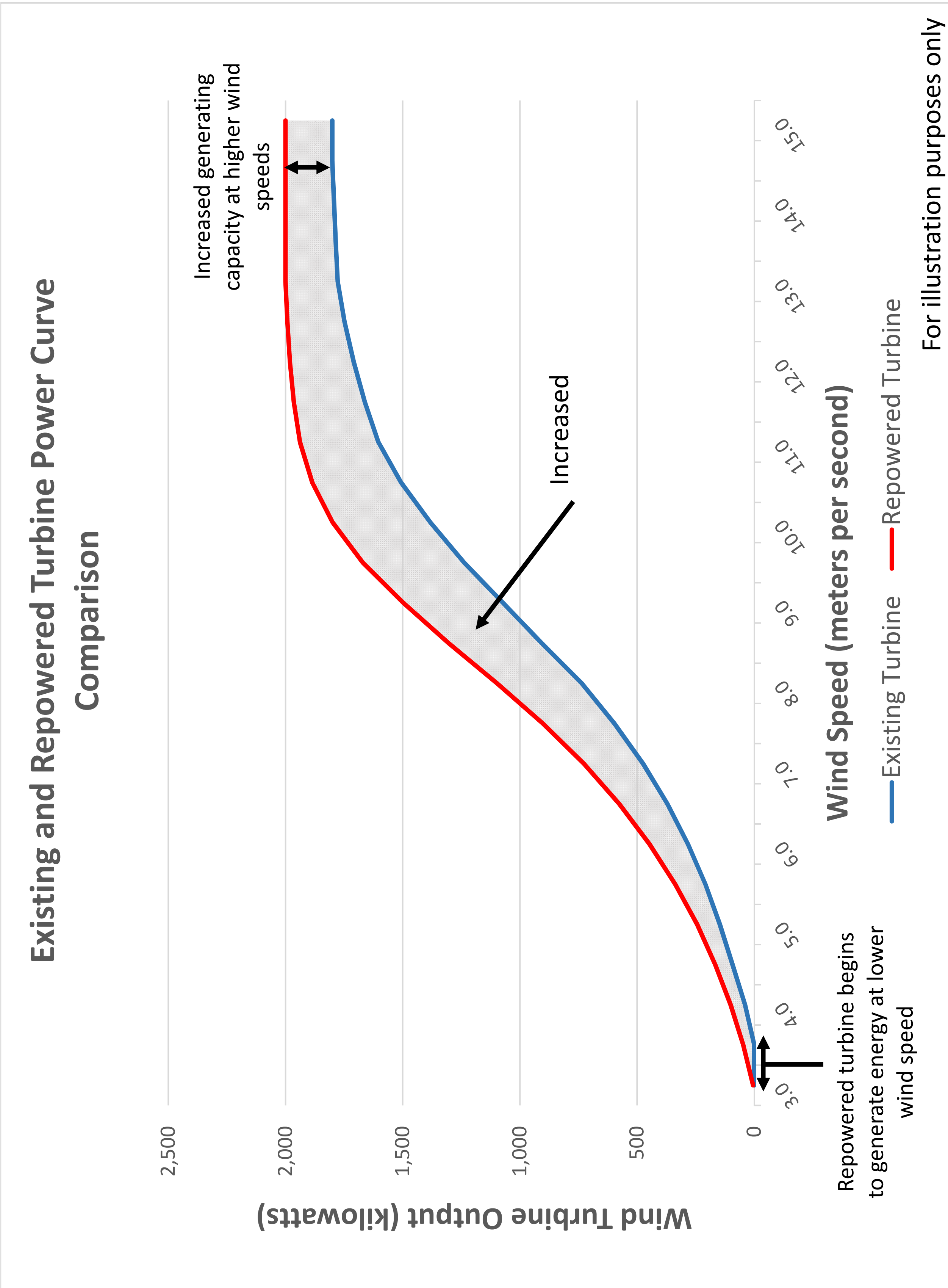
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Existing and Repowered Turbine Power Curve Comparison

May 2020


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
Increased generating capacity at higher wind speeds
Repowered turbine begins to generate energy at lower wind speed
For illustration purposes only