PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

December 28, 2018

VIA ELECTRONIC FILING
& OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: Advice No. 18-011/UE 352—Schedule 202—PacifiCorp's 2019 Renewable Adjustment Clause

In compliance with ORS 757.205, OAR 860-022-0025, OAR 860-022-0030, and ORS 757.210, PacifiCorp, d/b/a Pacific Power submits for filing with the Public Utility Commission of Oregon (Commission) the enclosed Schedule 202 Renewable Adjustment Clause Supply Service Adjustment (Schedule 202), of the company's Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules and regulations applicable to electric service in the State of Oregon. The company respectfully requests an effective date of October 1, 2019 for these tariff sheets.[1]

PacifiCorp makes this filing per the settlement agreement approved by the Commission in docket UE 339.

The purpose of this filing is to implement Schedule 202 rates to recover costs associated with the repowering of certain PacifiCorp wind resources as described further below and in the enclosed supporting testimony, and to make housekeeping changes to Schedule 202 to remove outdated language relating to Senate Bill 408.

A. Description of Filing

In Order No. 07-572, the Commission approved a Renewable Adjustment Clause (RAC) for PacifiCorp, under Senate Bill 838, enacted on June 6, 2007. The Commission directed PacifiCorp to file Schedule 202, to be effective January 1, 2008. In Advice No. 07-027, PacifiCorp filed Schedule 202 in compliance with Order No. 07-572. Schedule 202 provides that the company file any proposed charges under Schedule 202 by April 1 of each year, as necessary. These April 1 filings include new eligible renewable resources and associated transmission and are also used to update charges already included in the schedule.[2]

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[1] As discussed below, the company is proposing a second rate change effective on December 1, 2019. PacifiCorp proposes to submit a compliance filing with revised tariff sheets for rates effective on December 1, 2019 by November 1, 2019.

[2] Schedule 202 was most recently revised in April 2013 to remove reference to PacifiCorp's Schedule 33. Schedule 33, Klamath Basin Irrigation and Drainage pumping, was canceled on April 16, 2013 at the conclusion of the seven year transition rate period for these irrigation customers.

Beginning in 2018, PacifiCorp began upgrading or "repowering" 900.1 MW of company-owned and installed wind capacity through the addition of longer blades and new technology to generate more energy in a wider range of wind conditions.[3] These upgrades increase output of the company's wind facilities by 26.7 percent, on average, extend the operating life of the facilities and allow the facilities to requalify for federal production tax credits. This filing seeks approval to include the costs associated with these facilities, expected to come online by December 31, 2019, through the company's RAC.

In docket UE 339, PacifiCorp's 2019 Transition Adjustment Mechanism, the Commission approved a settlement in which parties agreed that PacifiCorp would file a RAC revision on January 2, 2019 (instead of April 1 as set forth in Schedule 202).[4] The parties to this settlement also agreed to support an expedited schedule to allow for rates effective by July 1, 2019. To reflect the current construction timelines and to accommodate the staggered in-service dates associated with the company's repowering facilities, PacifiCorp is now proposing two rate changes: the first rate change effective October 1, 2019 and the second rate change effective December 1, 2019. This timeline still allows PacifiCorp to seek contemporaneous recovery of the repowering projects without the need to file for a deferral of capital costs associated with the repowering projects. These staggered rate effective dates also allow for minimizing potential regulatory lag and maximizing of the matching of costs and benefits.[5]

The October 1, 2019 rate effective date will include the repowering projects for Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I. The December 1, 2019 effective date will include the repowering projects for Goodnoe Hills, High Plains, McFadden Ridge, Marengo I and Marengo II.

This tariff filing is supported by testimony and exhibits from the following company witnesses:

- Etta P. Lockey, Vice President, Regulation
- Timothy J. Hemstreet, Director, Renewable Energy Development
- Rick T. Link, Vice President, Resource Planning
- Steven R. McDougal, Director, Revenue Requirements
- Judith M. Ridenour, Specialist, Pricing and Cost of Service

Confidential information has been provided under Order No. 18-490.

This supporting testimony sets forth the benefits of repowering (including qualification for production tax credits), provides support for a finding that the investments were prudent and in the public interest, sets forth the details of the company's RAC and the company's proposal for ratemaking treatment of the repowering projects (including a description of the relevant portions

[3] The 900.1 MW capacity reflects all of PacifiCorp's wind repowering project, except Rolling Hills, which is not in Oregon rates. Inclusive of Rolling Hills, PacifiCorp is repowering 999.1 MW of company-owned wind capacity.
[4] A special condition is proposed for Schedule 202 which will accommodate a timeline different than the language currently in the tariff.
[5] The anticipated in-service date for these projects was July 1, 2019 at the time the stipulation agreement was entered in Docket No. UE 339.

of the settlement approved in docket UE 339), provides the construction timeline for the repowering projects, addresses how repowering was included in the company's Integrated Resource Plan, and provides the revenue requirement associated with the repowering projects.

In addition, PacifiCorp proposes a housekeeping edit to remove the second-to-last sentence in the Purpose section of Schedule 202 to remove outdated language associated with Senate Bill 408. The sentence references OAR 860-022-0041, which was repealed following the enactment of Senate Bill 967 in 2011 in the rulemaking docketed as AR 553. This housekeeping edit is appropriate because this language no longer applies.

B. Proposed Procedural Schedule

In the Stipulation approved in Order No. 18-421, the Commission approved the stipulating parties' agreement that the RAC would follow a schedule designed to allow for rates effective July 1, 2019. As noted above, the company is now requesting the first rate change for effect on October 1, 2019.[6] Based on this later effective date, PacifiCorp proposes the procedural schedule described as follows, subject to the availability of the Commission and interested parties:

RAC Filed	January 2, 2019
Prehearing Conference	January 23, 2019
Staff and Intervenor Testimony	March 6, 2019
Settlement Conference	April 3, 2019
Rebuttal Testimony	May 8, 2019
Hearing	June 25, 2019
Target Commission Decision	September 1, 2019
RAC Update Filing (if needed)	September 15, 2019
Effective Date for New Rates	October 1, 2019
Revised Tariff Sheet Filing	November 1, 2019
Effective Date for New Rates	December 1, 2019

To allow for the parties to conduct their review of the filing within this schedule, PacifiCorp requests the scheduling of a prehearing conference in this docket as soon as practicable and suggests January 23.

C. Tariff Sheets

Third Revision of Sheet No. 202-1	Schedule 202	Renewable Adjustment Clause
First Revision of Sheet No. 202-2	Schedule 202	Renewable Adjustment Clause

[6] The stipulating parties agreed that if the expected in-service date for the first RAC-eligible project goes beyond July 1, 2019, the stipulating parties would not oppose a later rate effective date. *See* Order 18-421, Appendix A at 4, fn. 5.

To support this filing and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, PacifiCorp submits proposed Schedule 202 as Exhibit PAC/502 and has included in the exhibits accompanying the direct testimony of Ms. Ridenour the following:

Exhibit PAC/501: Renewable Adjustment Clause, Rate Spread and Rate Calculations
Exhibit PAC/503: Estimated Effect of Proposed Price Changes
Exhibit PAC/504—Monthly Billing Comparisons for October 1
Exhibit PAC/505—Monthly Billing Comparisons for December 1

As shown on Exhibit PAC/503, the filing results in an overall increase of $16.0 million or 1.2 percent, on a net basis, effective October 1, 2019, followed by an incremental increase of $20.8 million 1.6 percent, on a net basis, effective December 1, 2019. This proposed change will affect approximately 614,000 customers. A residential customer using 900 kWh per month would see a monthly bill increase of $1.18 beginning October 1 plus an additional $1.51 beginning December 1. The total monthly bill increase for this customer from present rates is $2.69.

D. Correspondence

It is respectfully requested that all communications on this filing be addressed to:

Oregon Dockets PacifiCorp 825 NE Multnomah Street, Ste. 2000 Portland, OR 97232 oregondockets@pacificorp.com	Ajay Kumar Attorney 825 NE Multnomah Street, Ste 1800 Portland, OR 97232 Ajay.kumar@pacificorp.com

Additionally, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

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

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

Please direct informal correspondence and questions regarding this filing to Natasha Siores, Manager, Regulatory Affairs, at (503) 813-5542.

A copy of this filing has been served on all parties in dockets UE 263 and UE 339.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

cc: UE 263 Service List
UE 339 Service List

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's **Advice No. 18-011/UE 352—Schedule 202—PacifiCorp's 2019 Renewable Adjustment Clause** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 263

OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	GREGORY M. ADAMS RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE, ID 83702 greg@richardsonadams.com
GREG BASS NOBLE AMERICAS ENERGY SOLUTIONS, LLC 401 WEST A ST., STE. 500 SAN DIEGO, CA 92101 gbass@noblesolutions.com	KURT J BOEHM BOEHM KURTZ & LOWRY 36 E SEVENTH ST - STE 1510 CINCINNATI, OH 45202 kboehm@bkllawfirm.com
STEVE W CHRISS **(C)** WAL-MART STORES, INC. 2001 SE 10TH ST BENTONVILLE, AR 72716-0550 stephen.chriss@wal-mart.com	MARIANNE GARDNER **(C)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308-1088 marianne.gardner@state.or.us
KEVIN HIGGINS ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY, UT 84111-2322 khiggins@energystrat.com	ROBERT JENKS **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org
SARAH E LINK **(C)** PACIFIC POWER 825 NE MULTNOMAH ST STE 1800 PORTLAND, OR 97232 sarah.link@pacificorp.com	JODY KYLER COHN BOEHM, KURTZ & LOWRY 36 E SEVENTH ST STE 1510 CINCINNATI, OH 45202 jkyler@bkllawfirm.com
KATHERINE A MCDOWELL **(C)** MCDOWELL RACKNER & GIBSON PC 419 SW 11TH AVE., SUITE 400 PORTLAND, OR 97205 katherine@mrg-law.com	SAMUEL L ROBERTS **(C)** HUTCHINSON COX COONS ORR & SHERLOCK 777 HIGH ST STE 200 PO BOX 10886 EUGENE, OR 97440 sroberts@eugenelaw.com

TRACY RUTTEN LEAGUE OF OREGON CITIES 1201 COURT STREET NE SUITE 200 SALEM, OR 97301 trutten@orcities.org	IRION A SANGER **(C)** SANGER LAW PC 1117 SE 53RD AVE PORTLAND, OR 97215 irion@sanger-law.com
DONALD W SCHOENBECK **(C)** REGULATORY & COGENERATION SERVICES INC 900 WASHINGTON ST STE 780 VANCOUVER, WA 98660-3455 dws@r-c-s-inc.com	NONA SOLTERO FRED MEYER STORES/KROGER 3800 SE 22ND AVE PORTLAND, OR 97202 nona.soltero@fredmeyer.com
DOUGLAS C TINGEY PORTLAND GENERAL ELECTRIC 121 SW SALMON 1WTC1301 PORTLAND, OR 97204 doug.tingey@pgn.com	JAY TINKER PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC-0306 PORTLAND, OR 97204 pge.opuc.filings@pgn.com
MICHAEL T WEIRICH **(C)** PUC STAFF--DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@state.or.us	PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com

Dated December 28, 2018.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Advice No. 18-011/UE 352—Schedule 202—PacifiCorp's 2019 Renewable Adjustment Clause** on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

Service List
UE 339

ALLIANCE OF WESTERN ENERGY CONSUMERS	
MYRALEIGH ALBERTO **(C) (HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 maa@dvclaw.com	BRADLEY MULLINS **(C) (HC)** MOUNTAIN WEST ANALYTICS 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 brmullins@mwanalytics.com
TYLER C PEPPLE **(C) (HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE, ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO, CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY, UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	KATHERINE A MCDOWELL **(C)(HC)** MCDOWELL RACKNER & GIBSON PC 419 SW 11TH AVE., SUITE 400 PORTLAND, OR 97205 katherine@mcd-law.com
MATTHEW MCVEE **(C)(HC)** PACIFICORP 825 NE MULTNOMAH PORTLAND, OR 97232 matthew.mcvee@pacificorp.com	
STAFF	
SCOTT GIBBENS **(C)(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308-1088 george.compton@state.or.us	KAYLIE KLEIN **(C)(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 kaylie.klein@state.or.us
SOMMER MOSER **(C)(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us	

Dated this 28th day of December, 2018.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Docket No. UE 352
Exhibit PAC/100
Witness: Etta P. Lockey

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Etta P. Lockey

December 2018

DIRECT TESTIMONY OF ETTA P. LOCKEY

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

A. My name is Etta P. Lockey. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My title is Vice President, Regulation.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Juris Doctorate from the Northwestern School of Law of Lewis and Clark College. I started at PacifiCorp as an attorney in 2013 and assumed my current role as Vice President, Regulation in 2017.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously testified in regulatory proceedings in Oregon and California.

PURPOSE OF TESTIMONY

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

A. My testimony explains the benefits to customers from repowering the company's existing wind resources and outlines why wind repowering is an opportunity for customers that is both prudent and in the public interest. I also discuss PacifiCorp's Renewable Adjustment Clause (RAC) mechanism and describe the company's proposal for the ratemaking treatment of the repowering project, including a discussion of the relevant portions of the settlement approved by the Public Utility Commission of Oregon (Commission) in docket UE 339, PacifiCorp's 2019 Transition Adjustment Mechanism (TAM).

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. Beginning in 2018, PacifiCorp began upgrading or "repowering" 900.1 megawatts (MW) of company-owned, installed wind capacity (495 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.[1] The upgrades will increase output of the wind facilities by 26.7 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. PacifiCorp seeks to include in rates the costs associated with repowered facilities that are expected to come online by December 31, 2019.

Q. Please identify the other PacifiCorp witnesses supporting this RAC?

A. PacifiCorp'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 process and timing of wind-turbine generator (WTG) equipment purchases, construction requirements, construction timelines, and the disposition of removed equipment.

[1] The 900.1 MW capacity reflects all of PacifiCorp's wind repowering project, except Rolling Hills, which is not in Oregon rates. Inclusive of Rolling Hills, PacifiCorp is repowering 999.1 MW of company-owned wind capacity.

Mr. Rick T. Link, Vice President of Resource and Commercial Strategy, testifies on the economic analysis that supports the prudence of PacifiCorp's wind repowering project and quantifies customer benefit 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. Steven R. McDougal, Director of Revenue Requirements, provides the revenue requirement associated with the wind repowering project and explains the 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.

Ms. Judith M. Ridenour, Specialist**,** Pricing and Cost of Service, presents the company's proposed RAC prices and proposed tariff changes and provides the impact of the proposed rate changes on customers' bills.

RENEWABLE ADJUSTMENT CLAUSE

Q. Please describe PacifiCorp's RAC.

A. The RAC is the automatic adjustment clause created in accordance with Section 13 of Senate Bill 838 to allow for the timely recovery of costs associated with renewable portfolio standard compliance.[2] The RAC was adopted in 2007 through a stipulation agreed to by PacifiCorp, Portland General Electric Company, Staff, the Alliance of Western Energy Consumers (known at that time as the Industrial Customers of

[2] *See In the Matter of the Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 1 (Dec. 19, 2007).

Northwest Utilities), and the Oregon Citizens' Utility Board.[3] PacifiCorp's RAC is set forth in Schedule 202.[4]

Q. Has PacifiCorp previously used the RAC to incorporate renewable resources into rates?

A. Yes. The Commission authorized recovery through the RAC for PacifiCorp's investments in the Leaning Juniper, Marengo, and Blundell resources in 2008,[5] and Seven Mile Hill II and Glenrock III resources in 2009.[6]

Q. What is PacifiCorp's proposal for cost recovery through the RAC?

A. The company seeks to recover the revenue requirement associated with the investments related to the repowering of its wind resources as described in this filing, supported by the testimony and exhibits from the identified company witnesses. PacifiCorp proposes to implement cost recovery in two separate rate changes to accommodate the expected in-service completion dates of the repowering project. PacifiCorp expects to implement a rate change on October 1, 2019, for the completion of repowering at Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I, and a second rate change on December 1, 2019, for the completion of Goodnoe Hills, High Plans, McFadden Ridge, Marengo I and Marengo II. This approach minimizes the number of rate changes while also limiting regulatory lag on recovery of the completed repowered projects.

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[3] Order No. 07-572 at 2.
[4] Order No. 07-572, App. A at 20-21.
[5] *In the matter of PacifiCorp, dba Pacific Power, Application for an Accounting Order Approving Deferral of Costs Relating to Renewable Resources Pursuant to Senate Bill 838*, Docket No. UM 1338, Order No. 08-508 (Oct. 22, 2008).
[6] See *In the matter of PacifiCorp, dba Pacific Power, Application for Deferred Accounting*, Docket No. UM 1412, Order No. 09-072 (March 2, 2009) and Advice No. 09-015, Revising Schedule 203, Renewable Resource Deferral Adjustment, filed November 25, 2009, allowed (approved) on December 22, 2009.

Q. Does the company propose any updates to the RAC based on changes since the last RAC filing was implemented in 2009?

A. Yes. The company proposes to update the applicability of the RAC rate schedule to include direct access customers. PTCs have been included in the calculation of the TAM revenue requirement since 2017.[7] In the company's last TAM, UE 339, the final revenue requirement included the benefits of PTC's for the resources included in this RAC. Direct access customers receive the benefit of these PTCs through the calculation of their transition adjustments. Transition adjustments are a market-based credit for the energy freed up when a customer takes direct access offset by the cost of the TAM rate. Incorporating PTC credits into the TAM rate lowered the TAM rates and thereby increased the transition credits.[8] Since direct access customers are receiving the benefit of PTCs for these resources through transition adjustments, it is appropriate that the proposed RAC charges for these resources also apply to direct access customers.

Q. When costs for these RAC resources are rolled into base rates as part of a general rate case, will direct access customers pay those costs?

A. Yes. The cost of the RAC resources are generation costs that are recovered through Schedule 200, Base Supply Service. Direct access customers pay the rates in Schedule 200.

Q. Have proposed tariff changes been included in this filing?

A. Yes. The proposed tariff changes are provided in Exhibit PAC/502 accompanying the direct testimony of Ms. Ridenour.

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[7] Docket No. UE 307, PacifiCorp's 2017 Transition Adjustment Mechanism.
[8] Or, in the case where the transition adjustment is a charge, the inclusion of PTCs lowered the charge.

Q. Why is PacifiCorp filing the RAC now?

A. The RAC specifies that it will be filed on April 1, concurrent with the filing of a TAM. However, in PacifiCorp's 2019 TAM, the Commission approved a settlement in which parties agreed that PacifiCorp would file a RAC by January 2, 2019. Parties also agreed to support an expedited schedule to allow for conclusion of the RAC proceeding by July 1, 2019, before the first repowering facility is complete. This timeline allows PacifiCorp the opportunity to seek contemporaneous recovery of the repowering project without the need to file for a deferral of capital costs associated with the repowering projects.

Q. Does PacifiCorp's filing deviate from the RAC requirements in any other ways?

A. Yes. The RAC contemplates that both the costs and benefits of renewable projects be considered as part of the RAC filing. However, as part of the settlement in the 2019 TAM, PacifiCorp agreed to reflect the net power cost benefits, including the PTCs, in the 2019 TAM. The incremental generation provided by the repowered wind projects is zero-fuel-cost energy and either displaces higher cost energy or provides energy for off-system sales, thus reducing net power costs. In the 2019 TAM, net power costs were approximately $400,000 lower due to repowering. Additionally, the 2019 TAM includes approximately $4 million of customer benefits from PTCs.

Q. Please explain the timing differences that result from the costs and benefits being included in separate filings?

A. The repowering costs and benefits are aligned between the RAC and the 2019 TAM; however, there is a timing difference as to the impact to customer rates. For example, in the 2019 TAM customers will receive four months of repowering benefits for

Glenrock I since the benefits were included in the TAM beginning October 1, 2019 and this is the start date in the RAC to begin recovering the repowering costs. The timing difference is a result of the different rate effective dates between the 2019 TAM and the RAC. The inclusion of repowering benefits in the 2019 TAM allowed customers to begin receiving the benefits of the repowering project January 1, 2019. In other words, the four months of repowering benefits for Glenrock I are given to customers over the course of 2019. In the RAC, PacifiCorp will not begin to recover the costs associated with the repowering project until the first proposed rate change of October 1, 2019.

OVERVIEW OF REPOWERING

Q. Please describe the repowering of PacifiCorp's wind facilities.

A. Wind repowering takes advantage of technological advancements that enable increased generation from existing wind resources. PacifiCorp's wind repowering project involves installation of new rotors with longer blades and new nacelles with higher-capacity generators. These plant upgrades increase energy output without changing the footprint, towers, 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 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 projects in Oregon rates by 21 to 39 percent, resulting in an overall average generation increase of 26.7 percent. Mr. Hemstreet's testimony provides greater detail on the technical aspects of the wind repowering project.

Q. Why is PacifiCorp repowering its wind fleet?

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 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.

PacifiCorp's repowering efforts allow for the requalification for PTCs for the repowered wind facilities. To maximize the PTC benefit, in December 2016, PacifiCorp executed and took delivery of safe-harbor purchases with General Electric International, Inc., and Vestas-American Wind Technology, Inc. for new WTG equipment. These safe harbor equipment purchases were of sufficient value to allow the repowered facilities to qualify for 100 percent of available PTC benefits if they are commercially operational within four calendar years—*i.e.*, by the end of 2020. PacifiCorp's purchases in 2016 were important because wind facilities that began 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, declining an additional 20 percent each year until the PTC is entirely phased out for projects that come online after 2023. A delay in acquiring the safe harbor equipment would have made the economics of repowering less attractive and deprived customers of substantial benefits.

To meet the 2020 deadline, PacifiCorp ordered equipment and executed contracts in 2018 and will complete much of the construction in 2019. The renewal of the PTC has increased the demand for materials, equipment, and labor for wind facilities. By completing a substantial amount of construction in 2019, PacifiCorp will mitigate the risk of construction delays, or delays associated with the procurement of equipment while still allowing 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. As further described in the testimony and exhibits of Mr. Hemstreet, by achieving commercial operation in 2019 for most of the facilities, with the exception of Dunlap and Glenrock III (scheduled to be completed in 2020), PacifiCorp will also minimize the time during which the wind facilities are ineligible for PTCs.

Q. Which wind resources will be repowered?

A. PacifiCorp is repowering most of its Wyoming wind fleet (Glenrock I, Glenrock III, 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 results in a total of 1,035 MW of installed wind capacity, with 606 MW in Wyoming, 328 MW in Washington, and 101 MW in Oregon.

Q. Is PacifiCorp proposing to include all of these repowered wind resources in the RAC at this time?

A. No. PacifiCorp is seeking prudence review and rate recovery through the RAC for all of the projects listed above with the exception of the Dunlap and Glenrock III projects. The Glenrock III and Dunlap projects are not expected to come online until July 2020 and November 2020, respectively, and PacifiCorp will seek separate prudence review and rate recovery for these projects.

Q. What is the total repowering cost PacifiCorp is seeking recovery for at this time?

A. As described in Mr. McDougal's testimony the requested RAC recovery amounts are $16.0 million, through rates effective October 1, 2019, and an additional $20.8 million, through rates effective December 1, 2019.

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 PacifiCorp's existing wind resources to requalify for federal PTCs—the benefits of which the company has already started passing back to Oregon customers through decreased net power costs since January 1, 2019. As noted above, the total revenue requirement related to the cost of repowering, excluding Glenrock III and Dunlap, is $36.8 million. As described in the testimony of Mr. Link, the customer benefits, however, exceed the cost, meaning wind repowering will save customers money.

Wind repowering creates these benefits by:

- Increasing zero-fuel-cost energy production from wind facilities between 21 to 39 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 10 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 Oregon customers, while saving customers money over the life of the investment.

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

A. Yes. PacifiCorp's 2017 IRP, which was acknowledged by Commission Order No. 18-138 issued on April 27, 2018, includes wind repowering as an integral component of the preferred portfolio, meaning that it was selected as a least-cost, least-risk resource option.[9]

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

A. Yes. PacifiCorp'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, PacifiCorp 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 $121 million when assuming low natural gas and zero CO_2 prices to $466 million when assuming high natural gas and high CO_2 prices. With medium natural gas price and CO_2 price assumptions, wind repower results in

[9] *In the Matter of PacifiCorp dba Pacific Power, 2017 Integrated Resource Plan,* Docket No. LC 67, Order No. 18-138 (Apr. 27, 2018).

customer benefits of $273 million.

Q. Is the repowering project prudent and in the public interest?

A. Yes. 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 PacifiCorp's existing wind facilities, while saving customers money, and repowering provides these substantial customer benefits across all market price and Clean Power Plan[10] 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 Oregon customers. Therefore, PacifiCorp is requesting that the Commission find that the repowering of these facilities is prudent and in the public interest.

CONCLUSION

Q. What is your recommendation to the Commission?

A. I recommend that by September 1, 2019, the Commission issue an order finding that PacifiCorp'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.

Q. Does this conclude your direct testimony?

A. Yes.

[10] Subsequent to the filing of the 2017 IRP, the Energy Protection Agency withdrew its rulemaking on the Clean Power Plan, effectively suspending implementation of the Clean Power Plan.

REDACTED
Docket No. UE 352
Exhibit PAC/200
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Timothy J. Hemstreet

December 2018

DIRECT TESTIMONY OF TIMOTHY J. HEMSTREET

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ATTACHED EXHIBITS

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 Director of Renewable Energy Development.

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 PacifiCorp, 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.

Q. Have you testified in previous regulatory proceedings?

A. Yes.

PURPOSE OF TESTIMONY

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

A. In support of PacifiCorp's application for recovery of costs for its wind repowering project, my testimony provides technical information regarding the company's planned upgrades to "repower" most of its wind fleet. Specifically, my testimony addresses:

- The scope of the project;

- The financial 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;
- The extension of wind facility asset lives after repowering;
- Project contract status and construction schedule; and
- The disposition of removed equipment.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. The wind repowering project presents the opportunity to leverage prior investments in PacifiCorp's wind fleet and enhance the future value of these resources for customers. By executing wind turbine equipment purchases in late 2016, PacifiCorp secured the opportunity to repower and renew the wind fleet and qualify for the full value of the PTCs for another 10-year period. Repowering now provides a unique opportunity to return PacifiCorp'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 installation of longer blades on the existing towers and foundations, repowering will result in significantly more low-cost energy for customers—694 gigawatt-hours (GWh) annually, or an average increase of 26.7 percent. 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 in the testimony of Mr. Rick T. Link.

Q. What is the company's proposal in this proceeding?

A. PacifiCorp proposes to recover the costs of the wind repowering project through the Renewable Adjustment Clause (RAC). As described in my testimony, the Public Utility Commission of Oregon (Commission) should approve this proposal because the wind repowering project is prudent and provides significant benefits to customers.

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. Specifically, PacifiCorp's repowering plan involves replacing the nacelle, hub and rotor of the WTG. See Exhibit PAC/201 for a depiction of a wind turbine and its various components.

Q. Which facilities does PacifiCorp propose to repower?

A. By the end of 2019, PacifiCorp is planning to upgrade: (i) all of its wind facilities in Wyoming (except the company's Foote Creek I, Glenrock III and Dunlap facilities), including the facilities known as Glenrock I, Rolling Hills[1], Seven Mile Hill I, Seven Mile Hill II, High Plains, and McFadden Ridge; (ii) its Leaning Juniper facility in Oregon; and (iii) its Marengo I, Marengo II, and Goodnoe Hills facilities in

[1] The Rolling Hills wind project is not in Oregon rates and the company is not requesting in this filing to bring it in to Oregon rates through the RAC.

Washington. PacifiCorp plans to repower its Dunlap and Glenrock III facilities in Wyoming in 2020 and, as discussed below, is still evaluating whether it will proceed to repower its Foote Creek I facility in Wyoming. See Exhibit PAC/202 for a map depicting the locations of each of PacifiCorp's wind facilities.

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

A. PacifiCorp is planning to repower 11 of its 12 wind facilities that are in Oregon rates in 2019 and 2020, representing 900.1 MW of installed wind capacity.[2] Broken down by state, this consists of eight facilities in Wyoming comprising 495 MW, one facility in Oregon of 100.5 MW, and three facilities in Washington comprising 304.6 MW. Detailed information about the wind facilities PacifiCorp plans to repower is included in Exhibit PAC/203.

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

A. The wind facilities PacifiCorp proposes to repower began commercial operations between 2006 and 2010. Because of their age, they 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. 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.

[2] The 900.1 MW capacity reflects all of PacifiCorp's wind repowering project, except Rolling Hills, which is not in Oregon rates. Inclusive of Rolling Hills, PacifiCorp is repowering 999.1 MW of company-owned wind capacity.

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 removal of all of the old wind turbine equipment, including towers, foundations, and energy collection system, and replacement with new equipment and energy collector circuits appropriately sized for the new equipment.

Because PacifiCorp plans to repower its facilities in a way that allows the company to reuse the existing infrastructure of the towers, foundations, and energy collection systems, the energy and PTC benefits can be realized with a lower capital investment than would be required for the redevelopment of entire sites.

Q. Did PacifiCorp's 2017 Integrated Resource Plan (IRP) evaluate repowering all of the facilities described above?

A. Yes, except for Goodnoe Hills. When the 2017 IRP was developed, PacifiCorp had not assessed repowering Goodnoe Hills. Since that time, however, PacifiCorp has evaluated the facility and determined that Goodnoe Hills can be economically repowered similar to the facilities evaluated in the 2017 IRP. Mr. Link describes the company's analysis of the wind repowering project in the 2017 IRP, and the Commission's order on the 2017 IRP.

Q. Are the costs to repower the Dunlap and Glenrock III facilities in Wyoming included in this filing?

A. No. The Dunlap and Glenrock III facilities will be repowered in 2020, which is outside the 2019 period for this RAC filing. Consistent with the settlement agreement approved by the Commission in the 2019 Transition Adjustment Mechanism proceeding, docket UE 339, only the wind facilities repowered in 2019 are included in this filing.

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

A. As noted in the 2017 IRP action plan item 1a, PacifiCorp is still evaluating the potential of repowering Foote Creek I. Repowering this older facility would involve more comprehensive site redevelopment, as described above, which is different in scope than the repowering projects proposed here.

FINANCIAL BENEFITS OF REPOWERING INCLUDING REQUALIFICATION FOR PTCS

Q. What benefits will customers realize from wind repowering?

A. Repowering the proposed wind facilities will requalify them for PTCs, and these benefits will be fully passed on to PacifiCorp's customers through the Transition Adjustment Mechanism, beginning in 2019, as described in Ms. Etta P. Lockey's testimony (Exhibit PAC/100). Additionally, repowering will increase the amount of emissions-free energy produced from the repowered facilities by 21 to 39 percent, depending on the facility, as shown in Confidential Exhibit PAC/204.[3] Further, by

[3] This range reflects increases under existing transmission interconnection agreements. The range is 22 percent to 39 percent if transmission interconnection agreements are modified to reflect the additional capacity available from the repowered turbines.

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 at least 10 years, creating substantial energy and capacity 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. 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 the facilities are not placed in service 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 PacifiCorp'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, PacifiCorp executed safe-harbor equipment purchases with General Electric International, Inc. (GE) and Vestas American Wind Technology, Inc. (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.

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

A. For 2018, wind facilities that are qualified for the PTC will receive an estimated 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[4] (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 PacifiCorp 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.

[4] 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 and Glenrock III, which are located near Glenrock, Wyoming, will not include all wind turbines. At these locations, 14 of the 92 wind turbines will not be repowered because they were constructed atop mine tailings at the company's reclaimed Glenrock coal mine 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 PacifiCorp wind facility locations. Because the original construction cost of these foundations was higher than for standard foundations, the retained value of these foundations is also higher than the other foundations. For these 14 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. PacifiCorp plans to repower all of the turbines at the other wind facilities discussed above.

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

A. As shown in Exhibit PAC/203, several of the wind facilities PacifiCorp proposes to repower are still within 10 years of their original commercial online date, though most have just recently completed 10 years of operation. Thus, the PTCs from original construction have either recently expired or are still accruing to the benefit of PacifiCorp's customers for a small remaining period until these existing PTCs expire 10 years after the facilities' commercial online date. Between May 2018 and October 2020, the PTCs associated with approximately 2.0 terawatt-hours (TWh) of electricity generated at PacifiCorp's wind facilities in Oregon rates will expire. On an annual basis, in 2018 dollars, the expiration of these PTCs represents the loss of approximately $64 million per year in customer PTC benefits, as shown in Exhibit PAC/203.

To maximize the benefits of the existing PTCs available from the wind facilities, PacifiCorp will generally delay repowering until the original PTCs have expired. The exceptions to this are the High Plains, McFadden Ridge, and Dunlap facilities (although Dunlap is not included in this case). To take advantage of available construction capacity and the low-wind season in 2019, High Plains and McFadden Ridge repowering will begin in advance of when PTCs expire at those facilities in September 2019. In addition, if the company waited until the Dunlap PTCs expire in October 2020, there would be insufficient time to complete construction at Dunlap by the end of 2020, as required to re-qualify for PTCs. This results in a slight truncation of the existing, original 10-year PTC period for these facilities. As with all of the wind facilities, however, once these projects are repowered a new 10-year period will begin where its generation is eligible for the full value of PTCs.

Q. Have recent changes to federal tax laws impacted the ability of the repowering projects to qualify for PTCs?

A. No. The recent tax law changes enacted into law in December 2017 have not impacted the ability of the repowering projects to qualify 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 have a greater nameplate generating capacity than the equipment that is removed. For example, the nameplate rating of each turbine at the Wyoming facilities will increase from 1.5 MW to 1.85 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 PAC/204.

In addition to the larger generators in the repowered turbines, PacifiCorp will also install larger blades. With the larger blades, the rotor-swept area of the wind turbines will increase between 37 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 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. PacifiCorp 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. PacifiCorp's informed-curtailment protocols avoid avian impacts regardless of the swept area of the rotor. 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. How did PacifiCorp determine the amount of additional generation that will be produced from the repowered wind turbines?

A. PacifiCorp worked with its consultant, Black & Veatch (B&V), to use the extensive data history from PacifiCorp's facilities to derive precise estimates of the energy production expected from repowering. This analysis used millions of data points from the operational record of the wind facilities 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 following repowering will increase as shown in Confidential Exhibit PAC/204, 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 likely are 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 enter into service agreements with the turbine suppliers GE and Vestas 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. 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 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. Exhibit PAC/205 illustrates these power production advantages and compares the power curve of an existing wind turbine to that of a repowered wind turbine.

Q. Why did PacifiCorp not install this larger equipment 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 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, 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 PAC/204, across the wind fleet, the proposed repowered wind facilities are estimated to increase generation by 694 GWh per year if the facilities are operated within the limits of their existing large generator interconnection agreements—an increase of 26.7 percent.

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

A. Yes. To use the additional maximum generating capacity of the facilities provided by the repowered wind turbines, PacifiCorp will need to modify its existing transmission interconnection agreements for these facilities. Accordingly, PacifiCorp has filed generation interconnection applications for the additional generation at the existing points of interconnection for the planned repowering projects, except for Leaning Juniper and Goodnoe Hills. Due to transmission constraints at Leaning Juniper and Goodnoe Hills, PacifiCorp does not expect additional transmission capacity to be available for those facilities.

PacifiCorp's transmission function is currently reviewing the submitted applications and preparing the required studies under the company's Open Access Transmission Tariff. Two separate studies are required, including (i) a system impact study and (ii) a facilities study. The completed studies will provide information on the transmission upgrades, if any, needed to accommodate the interconnection request. Once all studies are complete, PacifiCorp's transmission function will determine if it can offer revised Large Generator Interconnection Agreements to the company's merchant function.

Transmission studies for the Marengo I and Marengo II facilities have been completed and the company has executed a new interconnection agreement with PacifiCorp's transmission function that allows the additional capacity to be interconnected so that these facilities can deliver the increased capacity and the associated energy to customers. The remaining transmission studies are still pending.

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

A. Yes. Mr. Link demonstrates in his testimony (Exhibit PAC/300) that the repowering project is economic even if the facilities are operated within their existing transmission capacity limits. An adjustment to the large-generator interconnection agreements to allow the facilities to be operated at full nameplate capability following repowering simply improves the already favorable economics of the repowering project. Because of the uncertainty regarding the ability of the Wyoming wind facilities to interconnect the additional capacity, PacifiCorp's economic analysis is based upon a scenario in which the Wyoming projects are operated within the existing capacity of their transmission interconnection agreements.

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 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 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 12 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.

The repowering project will also result in more certainty related to ongoing operations and maintenance costs of the existing wind facilities. PacifiCorp will execute full service agreements on the new GE turbines under which GE will be responsible for operating and maintaining the new turbines for a fixed cost while attaining a guaranteed production-based availability on 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 operations and maintenance costs fixed for the term of the agreement. Thus, there is greater cost certainty related to the run-rate capital expenditures and operations and maintenance costs of the repowering projects in addition to the cost certainty related to construction. PacifiCorp's negotiated full service agreement with GE is for a [redacted]. For facilities employing Vestas turbines, PacifiCorp has executed service agreements [redacted].

Q. Will PacifiCorp'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 will experience component failures that render them unable to be economically returned to service. It will be more economic for customers to idle these turbines than repair them given the short period before repowering. As a result, PacifiCorp estimates that generation from the wind facilities targeted for repowering will be reduced before repowering. These estimates of pre-repowering generation impacts are factored into the economic analysis presented in Mr. Link's testimony.

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 the 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 projects. These gearboxes, which are original equipment from the manufacturers, are experiencing high failure rates compared to other models of gearboxes installed in WTGs at these facilities and elsewhere within the wind fleet. Consequently, PacifiCorp 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". 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 are expected if there is no repowering?

A. There are 230 of these gearbox models remaining in the wind fleet, and PacifiCorp 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. Three of the 14 wind turbines that will not be repowered at Glenrock I and Glenrock III 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 PacifiCorp'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 to address a blade design deficiency account for approximately 60 percent of the budgeted capital costs associated with blade failures and refurbishments across PacifiCorp'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 PacifiCorp'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 while extending asset life, increasing generation, and 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. Further, the equipment that will be installed has evolved from the product lines of the existing turbines, rather than arising from entirely new product offerings. Thus, the turbine suppliers have had time to learn from their past experience with these turbine models and have 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—such as will be the case with the GE turbines—the turbine suppliers have an incentive to improve the reliability of their turbines. Thus, PacifiCorp does not expect to have the problems and expense it has had in the past with specific gearbox models and the associated reliability concerns.

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 PacifiCorp plans to repower are currently scheduled to be retired between 2036 and 2040 (see Confidential Exhibit PAC/204).

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 30 years from the repowering date, adding approximately 10 years to their planned retirement dates.

Q. How will repowering extend the useful life by 30 years from the repowering date?

A. The repowering projects are being designed by the turbine equipment suppliers to meet the same design requirements that apply to WTGs 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 climatic 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 PacifiCorp reviewed the foundations to ensure they are capable of handling the new turbines?

A. Yes. PacifiCorp retained B&V to evaluate the ability of the existing foundations to handle the loads of the repowered turbines. B&V's evaluation indicates that the existing foundations are suitable for the repowered turbines. At the Leaning Juniper and Goodnoe Hills facilities, the foundations will require a standard retrofit to increase their strength.

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

A. Yes. For the foundations in which fatigue loading is a controlling design variable, B&V has assessed the ability of the foundations to handle the estimated fatigue loading anticipated for a 30-year period following repowering and has determined that all the foundations will be able to accommodate the additional loading.

PROJECT CONTRACT STATUS AND CONSTRUCTION SCHEDULE

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

A. PacifiCorp has executed a master retrofit contract with GE for the Wyoming projects and the Leaning Juniper project in Oregon, and has executed turbine supply contracts with Vestas for the other three projects. The scope, language, and risk profile of the agreements with each of the companies is different.

The master retrofit contract commits GE to perform turn-key supply, delivery, installation, and commissioning of the repowering turbines at a fixed price. PacifiCorp has also executed fixed-price turbine supply agreements with Vestas and has executed and negotiated separate contracts with wind energy construction companies for installation of the Vestas equipment.

Q. Has PacifiCorp begun the repowering projects under the GE master retrofit contract?

A. Yes. Retrofit work orders have been issued for all of those projects and the majority of construction work will be completed in 2019.

Q. Are the projects with Vestas also moving forward at this time?

A. Yes. The turbine supply contracts with Vestas for the repowering of the Marengo I, Marengo II and Goodnoe Hills facilities have been executed and Vestas is currently manufacturing the equipment that will be supplied for the projects.

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

A. No. The contracts provide that the prices are fixed and have no adjustment mechanisms for those common price indexes. Generally, the turbine suppliers can only seek a change order for price relief as a result of changes in state and/or local law that impacts their costs. As such, the vast majority of repowering costs are now fixed under these negotiated contracts which substantially reduces risk of cost over-run.

Q. When will the repowering projects be constructed?

A. The repowering projects will mostly be completed in 2019—a year in advance of the deadline for completing construction and achieving commercial operations of other repowered facilities. PacifiCorp'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. A detailed project schedule for the repowering projects is attached as Confidential Exhibit PAC/206.

Q. How has PacifiCorp designed the repowering projects to work within PTC-timing constraints?

A. As discussed above, the 2019 construction schedule for most of the facilities 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 has the company obtained all the necessary permits to ensure the construction schedule will not be delayed due to permitting issues?

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 are limited. PacifiCorp has obtained all of the necessary major permits required for the repowering projects to be completed, such as Federal Aviation Administration permits, county conditional use permits, and Wyoming Industrial Siting Division approvals. Necessary building permits, where not already in hand, will be obtained a few months before construction efforts begin. Throughout the repowering process PacifiCorp 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.

DISPOSITION OF REMOVED EQUIPMENT

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

A. PacifiCorp has issued a request for proposals related to the disposition of the existing equipment that will be removed and is still evaluating those proposals against options for equipment disposal that have been offered by the repowering construction contractors. Because PacifiCorp 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.

PacifiCorp 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 of PacifiCorp'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. PacifiCorp has not assumed any salvage value for the removed equipment in its economic analysis. To the extent PacifiCorp 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.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 352
Exhibit PAC/201
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

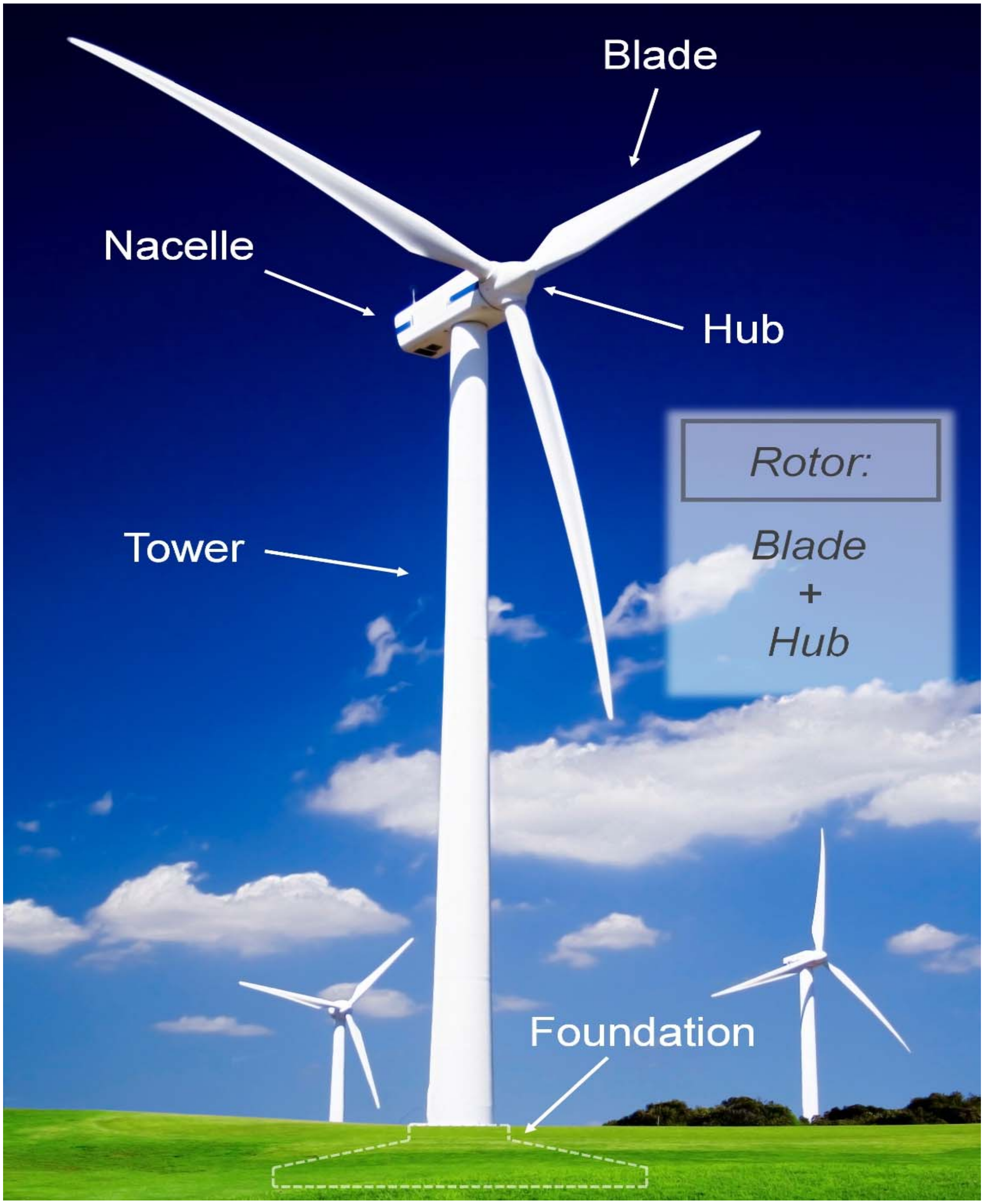
PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Major Components of a Wind Generator

December 2018

Exhibit PAC/201
Major Components of a Wind Turbine Generator



Docket No. UE 352
Exhibit PAC/202
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

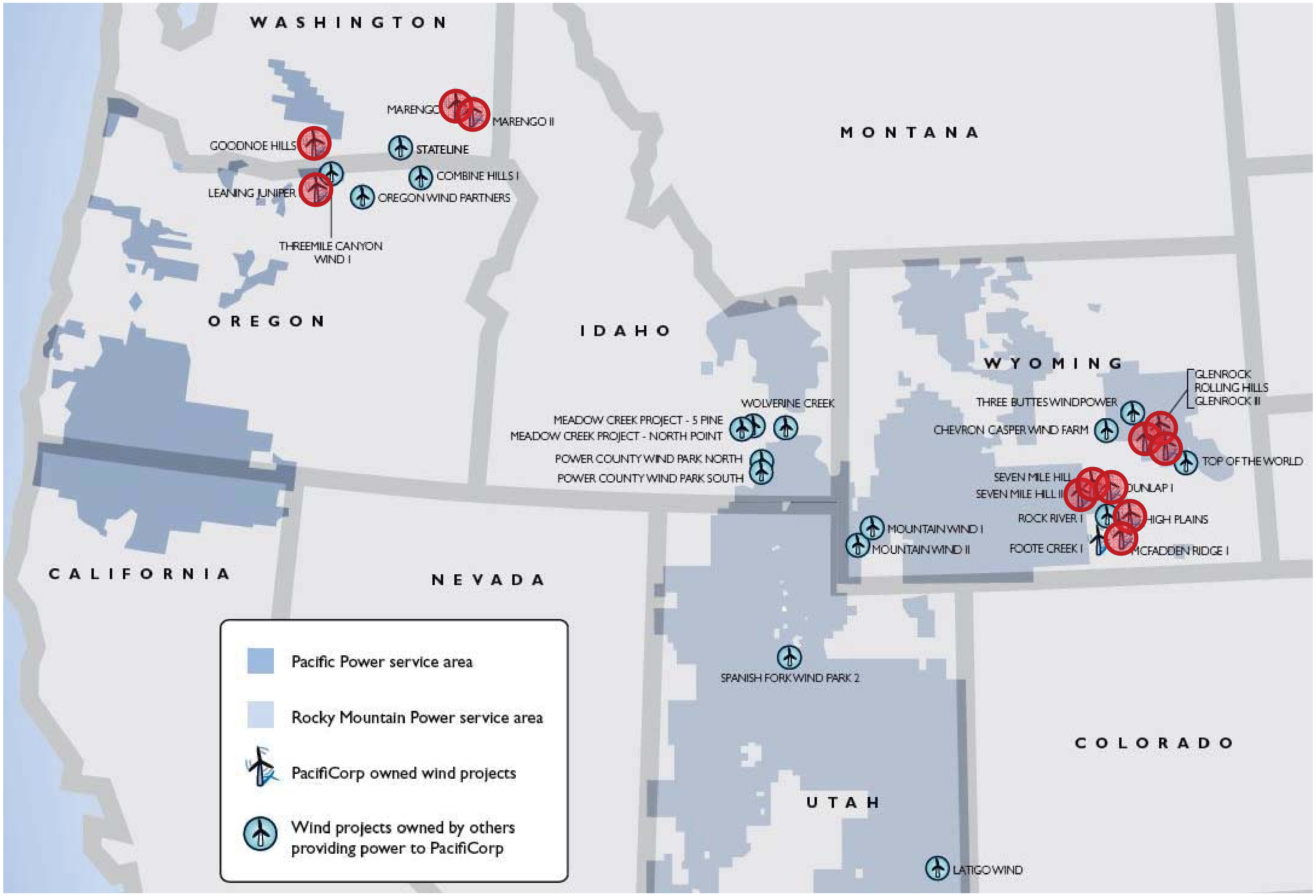
PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Wind Facilities Map

December 2018

Facilities Proposed to be Repowered



Docket No. UE 352
Exhibit PAC/203
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

List of Projects to be Repowered

December 2018

Exhibit PAC/203

PacifiCorp Wind Fleet Repowering

List of projects to be repowered

Project #	Wind Project	Location	Commercial Online 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	10.0	66	99.0	303,723
2	Glenrock III	Glenrock, WY	1/17/2009	9.9	26	39.0	113,438
3	Seven Mile Hill I	Medicine Bow, WY	12/31/2008	10.0	66	99.0	339,195
4	Seven Mile Hill II	Medicine Bow, WY	12/31/2008	10.0	13	19.5	71,224
5	High Plains	McFadden, WY	9/13/2009	9.3	66	99.0	306,145
6	McFadden Ridge	McFadden, WY	9/29/2009	9.2	19	28.5	93,101
7	Dunlap I	Medicine Bow, WY	10/1/2010	8.2	74	111.0	389,045
					330	**495.0**	**1,615,870**
Washington Projects							
8	Marengo I	Dayton, WA	8/3/2007	11.4	78	140.4	360,279
9	Marengo II	Dayton, WA	6/26/2008	10.5	39	70.2	166,742
10	Goodnoe Hills	Goldendale, WA	5/31/2008	10.6	47	94.0	220,898
					164	**304.6**	**747,919**
Oregon Project							
11	Leaning Juniper	Arlington, OR	9/14/2006	12.3	67	100.5	233,592
				TOTAL	**561**	**900.1**	**2,597,381**

Annual generation from projects with PTCs expiring between May 2018 and October 2020 (MWh)	**2,003,510**
2018 PTC Value ($/MWh)	**$24.00**
PacifiCorp effective combined federal and state income tax rate	**24.587%**
Pending loss in customer PTC benefits with expiration of original PTCs from wind plants (2018$)	**$ 63,761,198**

REDACTED
Docket No. UE 352
Exhibit PAC/204
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Repowering Project Details, Capital Costs, and In-Service Dates

December 2018

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PacifiCorp Wind Fleet Repowering

Table 1: Repowering Project Details, Capital Costs, and In-Service Dates

Project #	Wind Project	WTGs	WTGs to be Repowered	Current Project Capacity (MW)	Current Long-Term Generation (MWh)	Current Capacity Factor	Future Project Capacity (MW)	Project In-Service Date	Retirement date without Repowering	Retirement date with Repowering	Additional Life (Years)
					Wyoming Projects						
1	Glenrock I	66	58	99.0	303,723	35.0%	119.7	9/14/2019	12/31/2038	9/30/2049	10.75
2	Glenrock III	26	20	39.0	113,438	33.2%	46.3	7/18/2020	12/31/2038	7/31/2050	11.58
3	Seven Mile Hill I	66	66	99.0	339,195	39.1%	122.1	9/2/2019	12/31/2038	9/30/2049	10.75
4	Seven Mile Hill II	13	13	19.5	71,224	41.7%	24.1	9/2/2019	12/31/2038	9/30/2049	10.75
5	High Plains	66	66	99.0	306,145	35.3%	122.1	11/19/2019	12/31/2038	11/30/2049	10.92
6	McFadden Ridge	19	19	28.5	93,101	37.3%	35.2	11/19/2019	12/31/2038	11/30/2049	10.92
7	Dunlap I	74	74	111.0	389,045	40.0%	136.9	11/17/2020	10/1/2040	11/30/2050	10.16
		330	**316**	**495.0**	**1,615,870**	**37.3%**	**606.2**				
					Washington Projects						
8	Marengo I	78	78	140.4	360,279	29.3%	156.0	11/29/2019	8/1/2037	11/30/2049	12.33
9	Marengo II	39	39	70.2	166,742	27.1%	78.0	11/29/2019	6/1/2038	11/30/2049	11.50
10	Goodnoe Hills	47	47	94.0	220,898	26.8%	94.0	10/2/2019	12/31/2038	10/31/2049	10.83
		164	**164**	**304.6**	**747,919**	**28.0%**	**328.0**				
					Oregon Project						
11	Leaning Juniper	67	67	100.5	233,592	26.5%	100.5	8/7/2019	9/14/2036	8/31/2049	12.96
12	**TOTAL**	**561**	**547**	**900.1**	**2,597,381**	**32.9%**	**1,034.7**				

CONFIDENTIAL

PacifiCorp Wind Fleet Repowering

Project #	Wind Project	Current Net Capacity (MW)	Current Long-Term Generation (MWh)	Base Case Repowering Scenario (Current Transmission Interconnection/Service Limits except at Marengo)			
				Project Generation Increase (%)	Incremental Energy (MWh)	Repowered Project Generation (MWh)	Capital Cost ($m)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Wyoming Projects							
1	Glenrock I	99.0	303,723	21.7%	65,999	369,722	[redacted]
2	Glenrock III	39.0	113,438	20.7%	23,425	136,863	[redacted]
3	Seven Mile Hill I	99.0	339,195	23.0%	78,049	417,244	[redacted]
4	Seven Mile Hill II	19.5	71,224	22.8%	16,253	87,477	[redacted]
5	High Plains	99.0	306,145	24.9%	76,261	382,406	[redacted]
6	McFadden Ridge	28.5	93,101	25.3%	23,545	116,647	[redacted]
7	Dunlap I	111.0	389,045	22.5%	87,691	476,735	[redacted]
		495.0	**1,615,870**	**23.0%**	**371,223**	**1,987,093**	[redacted]
Washington Projects							
8	Marengo I*	140.4	360,279	35.5%	127,935	488,214	[redacted]
9	Marengo II*	70.2	166,742	39.4%	65,680	232,421	[redacted]
10	Goodnoe Hills**	94.0	220,898	28.4%	62,801	283,699	[redacted]
		304.6	**747,919**	**34.3%**	**256,416**	**1,004,334**	[redacted]
Oregon Project							
11	Leaning Juniper**	100.5	233,592	28.3%	66,153	299,745	[redacted]
12	**TOTAL**	**900.1**	**2,597,381**	**26.7%**	**693,792**	**3,291,172**	**$997.2**

Notes: *Marengo I and Marengo II are assumed to have transmission interconnection agreements modified under both scenarios.

**Goodnoe Hills and Leaning Juniper are not assumed to operate under revised transmission interconnection agreements with increased capacity.

Docket No. UE 352
Exhibit PAC/205
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Existing and Repowered Turbine Power Curve Comparison

December 2018

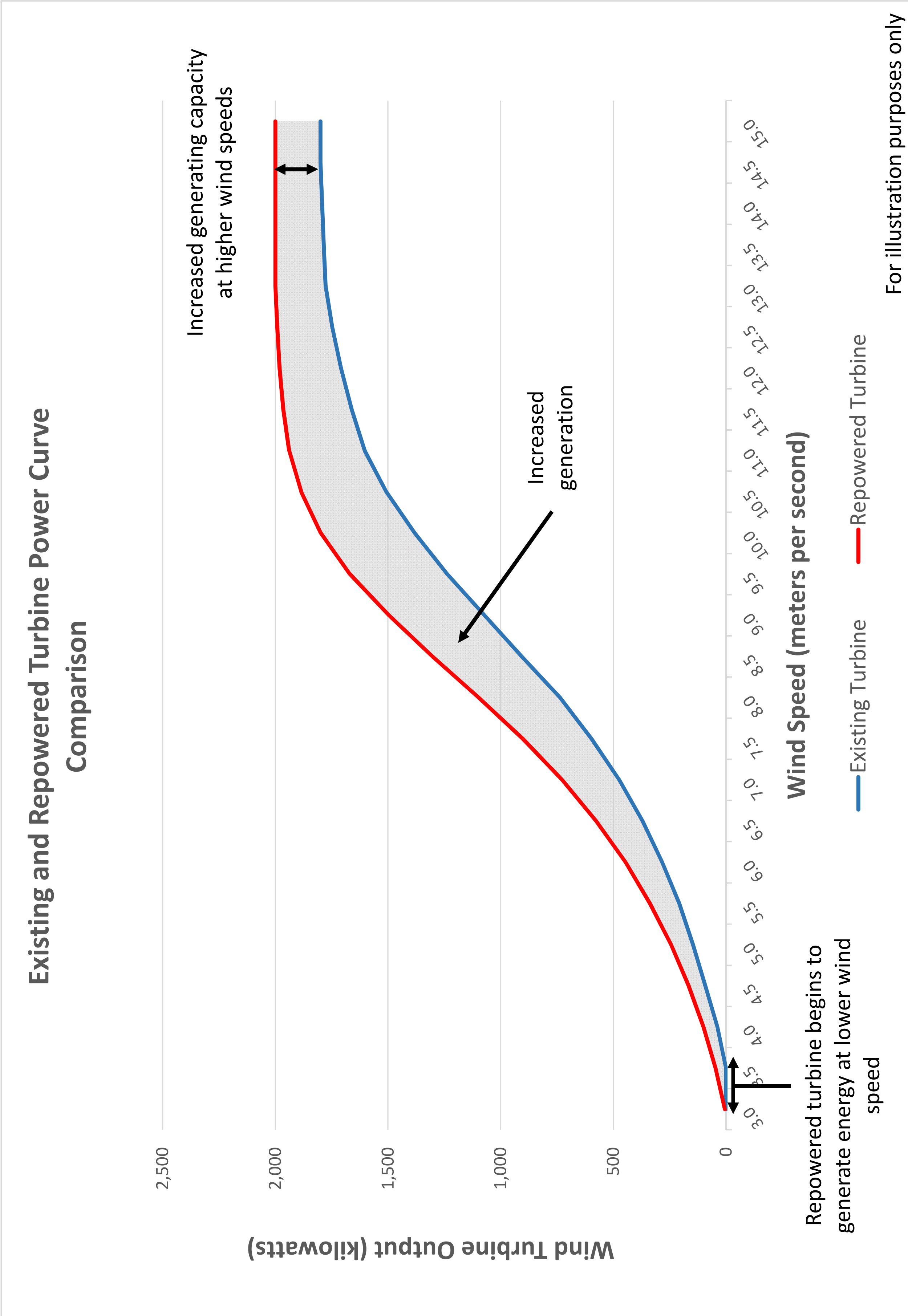

Exhibit PAC/205

REDACTED
Docket No. UE 352
Exhibit PAC/206
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Wind Repowering Project Schedule

December 2018

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

REDACTED
Docket No. UE 352
Exhibit PAC/300
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Rick T. Link

December 2018

DIRECT TESTIMONY OF RICK T. LINK
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ATTACHED EXHIBITS

Q. Please state your name, business address, and present 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 Planning and Acquisitions.

QUALIFICATIONS

Q. Please describe your current responsibilities.

A. I am responsible for PacifiCorp's integrated resource plan (IRP), implementing resource request-for-proposals (RFP), structured commercial business and valuation activities, long-term commodity price forecasts, and long-term load forecasts. Most relevant to this proceeding, I am responsible for the economic analysis used to screen significant resource investments.

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 RFPs, 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 Public Utility Commission of Oregon (Commission), and the public utility commissions in Washington, California, Idaho, Utah, and Wyoming.

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 wind repowering opportunities in the 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis supports repowering approximately 999.1 megawatts (MW) of existing wind resource capacity for twelve wind facilities—Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap in Wyoming; Marengo I, Marengo II and Goodnoe Hills in Washington; and Leaning Juniper in Oregon—in 2019 and 2020. Nine of these facilities are included in this filing. The three facilities excluded from this filing are two planned for construction in 2020 (Glenrock III and Dunlap) and Rolling Hills, which is not in Oregon rates.

The repowered wind facilities will qualify for an additional 10 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 project 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.

Based on an economic analysis completed in February 2018, my testimony shows that:

- The wind repowering project will deliver net customer benefits in all price-policy scenarios studied.
- The wind repowering project will produce present-value net customer benefits, based on analysis covering the remaining life of the repowered wind facilities, ranging between $121 million to $466 million (total system).
- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value project costs totaling $1.01 billion.
- These net and gross customer benefits are conservative, as they do not account for potential incremental benefits from renewable energy certificates (RECs), understate the potential benefits from reduced carbon-dioxide emissions, and assign no incremental capacity value associated with extending the life of the repowered wind facilities by 10-13 years.
- When measured over a 20-year period, the present value of net customer benefits from wind repowering range between $139 million and $273 million, which accounts for the nominal value of federal PTCs, but does not account for the value of incremental energy output that will increase significantly beyond 2036.

PacifiCorp performed updated analysis in August 2018 to understand how more recent changes in other modeling assumptions affect project-by-project results relative to those included in the February 2018 analysis. Based on this updated economic analysis, my testimony shows that projected net customer benefits remain similar to those calculated previously. This targeted reassessment confirms that the repowering project is prudent. As with the February 2018 results, the net customer benefits projected in the August 2018 analyses are conservative, as they do not account for potential incremental benefits from RECs, and assign no incremental capacity value associated with extending the life of the repowered wind facilities by 10-13 years.

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 905 MW of existing wind resource capacity located in Wyoming, Washington, and Oregon. As discussed later in my testimony, PacifiCorp has since expanded the wind repowering scope to include its Goodnoe Hills wind facility. With the addition of Goodnoe Hills, PacifiCorp is proceeding with its plans to repower approximately 999.1 MW of existing wind capacity.

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

A. As explained in Mr. Timothy J. Hemstreet's testimony (Exhibit PAC/200), 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 24.587 percent, the current PTC equates to a $31.82/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 reduce failure rates for certain wind turbine components within the wind fleet. 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 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 potential net customer benefits.

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 Plains, 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 the scope of the wind repowering project 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 customer benefits across a range of assumptions related to forward market prices and possible federal carbon-dioxide (CO_2) policy.

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

A. Yes. The wind repowering sensitivity 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 actions.

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

A. Yes. The 2017 IRP action plan, which lists 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 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

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

repowering opportunities, and is now including Goodnoe Hills in the wind repowering project. Since the 2017 IRP, the economic analysis has been updated to reflect more current assumptions, including changes in the federal tax rate for corporations. The rest of my testimony presents and explains this economic analysis. 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 included in the economic analysis of the wind repowering project at this time. Mr. Hemstreet also discusses the status of the construction agreements and addresses the construction schedule.

Q. Did the Commission acknowledge the 2017 IRP?

A. Yes. The Commission acknowledged the 2017 IRP in Order No. 18-138, issued on April 27, 2018.[2] The Commission conditioned its acknowledgement of Energy Vision 2020 projects, which includes the wind repowering project, by reserving the right to conduct a full reasonableness review in the future and limit risks to customers, and requiring an updated economic analysis in the 2017 IRP Update.

Q. Did PacifiCorp update its wind repowering analysis in its 2017 IRP Update, filed on May 1, 2018?

A. Yes. PacifiCorp filed its 2017 IRP Update on May 1, 2018. The IRP Update includes a summary of the February 2018 analysis I discuss below.

[2] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket LC 67, Order No. 18-138, 7-9 (April 27, 2018).

MODELING SCOPE, METHODOLOGIES, AND ASSUMPTIONS

Q. What wind resources did PacifiCorp include in its economic analyses of the wind repowering project, and how do those resources relate to this filing?

A. The economic analyses described in my testimony cover the entire repowering project, which consists of twelve wind facilities, in order to estimate customer benefits from repowering approximately 999.1 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington in 2019 and 2020. These economic analyses informed PacifiCorp's decision to move forward with the project. As noted above, nine of these facilities are included in this filing, and three are excluded (Glenrock III, Dunlap, and Rolling Hills).

Modeling Methodology

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

A. PacifiCorp relied on 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 a 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 net benefits when the system PVRR with wind repowering is lower than the system PVRR without wind 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 economic 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 new 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 (O&M), 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 PaR reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable O&M 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 O&M 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 the SO model has been used to evaluate installation of emissions control systems. These models were also be used to evaluate bids in PacifiCorp's recent 2017R RFP, issued to solicit bids for new wind resources, and in PacifiCorp's recent 2017S RFP, issued to solicit bids for new solar 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 95th 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. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and the PaR in the economic analysis.

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. Accounting for recent changes in tax law, the discount rate used in the economic analysis is 6.91 percent.

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

Finally, the income tax rate affects the tax gross-up of all PTC-eligible resources. The current value of federal PTCs is $24/MWh, which equates to a $31.82/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 24.587 percent. The impact of the income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

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 assumptions. These price-policy 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.

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

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. This project-by-project analysis was performed by running one SO model simulation that included the full scope of the wind repowering project and then 12 separate SO model simulations where one of the repowered wind facilities is assumed to be excluded from the scope of the wind repowering project. The total system cost from the SO model simulation where all facilities are repowered and from the SO model simulation where one facility is removed from scope is used to calculate the marginal PVRR(d) for each wind facility. Using the resource portfolio from the SO model simulations, this same approach was used to calculate the PVRR(d) for each wind facility using projected system costs from PaR.

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 $1.101 billion with a 25.7 percent average increase in annual energy output (738 gigawatt-hours (GWh) per year). The cost-and-performance assumptions for the wind facilities studied in this updated economic analysis are summarized in Confidential Exhibit PAC/301. In addition, as described further below, several other assumptions were updated in the August 2018 analysis to align with updates included in the 2017 IRP Update, which was filed after the February 2018 analysis was completed.

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 30-year depreciable life of each repowered facility.

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 Methodology

Q. In addition to the system modeling used to calculate present-value net benefits over a 20-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 O&M) 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 O&M 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. I present two vintages of the wind repowering economic analysis—a complete set of studies was prepared in February 2018 and a more targeted set of studies was prepared in August 2018 as validation.[3] The February 2018 analysis represents the final set of studies used to support PacifiCorp's pre-approval proceedings in Idaho, Utah, and Wyoming. The August 2018 analysis was prepared to understand how updates to certain modeling assumptions, which I describe later in my testimony, affect the economic analysis that was prepared in February 2018. The specific price-policy scenarios used in each of these studies are described further below.

February 2018 Price-Policy Assumptions

Q. What price-policy assumptions did PacifiCorp use in its February 2018 wind repowering analysis?

A. PacifiCorp developed three wholesale-power price scenarios (low, medium, and high), and similarly developed three CO_2 policy scenarios (zero, medium, and high).

[3] For preapproval proceedings in other states, PacifiCorp performed an earlier project-wide study in early 2017. That study predated tax code reforms and was therefore supplanted by the February 2018 analysis, so I do not describe it further in this testimony.

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 recognizing that 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.

Q. Please describe the natural-gas price assumptions used in the February 2018 price-policy scenarios.

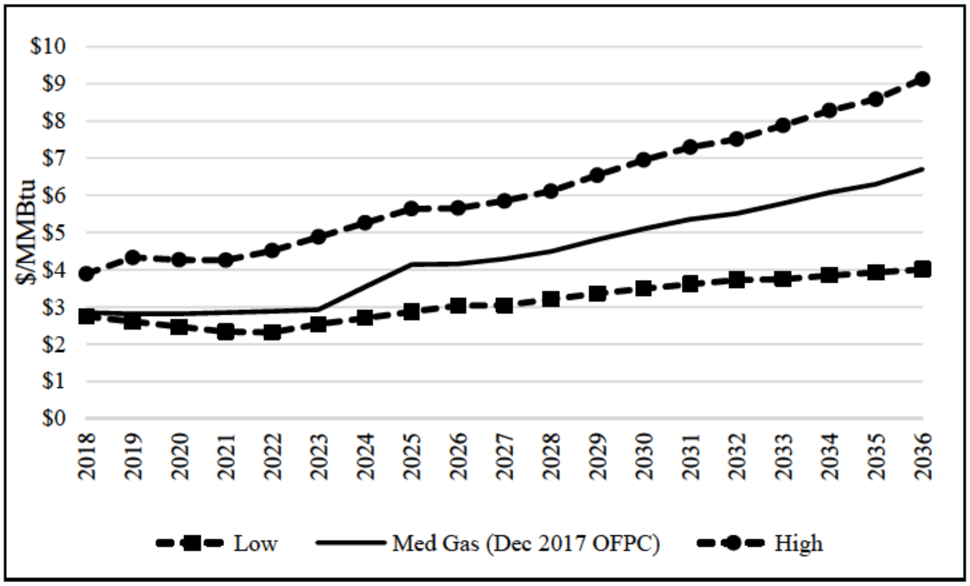
A. The medium-natural-gas price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's official forward price curve (OFPC) dated December 29, 2017. This OFPC uses observed forward market prices as of December 29, 2017, for 72 months, followed by a 12-month transition 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. Confidential Exhibit

PAC/302 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]. The medium-natural-gas price assumption, which is used beyond month 84 in the December 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] that is characterized by exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in this 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 December 2017 OFPC, low-, and high-natural-gas price scenarios.

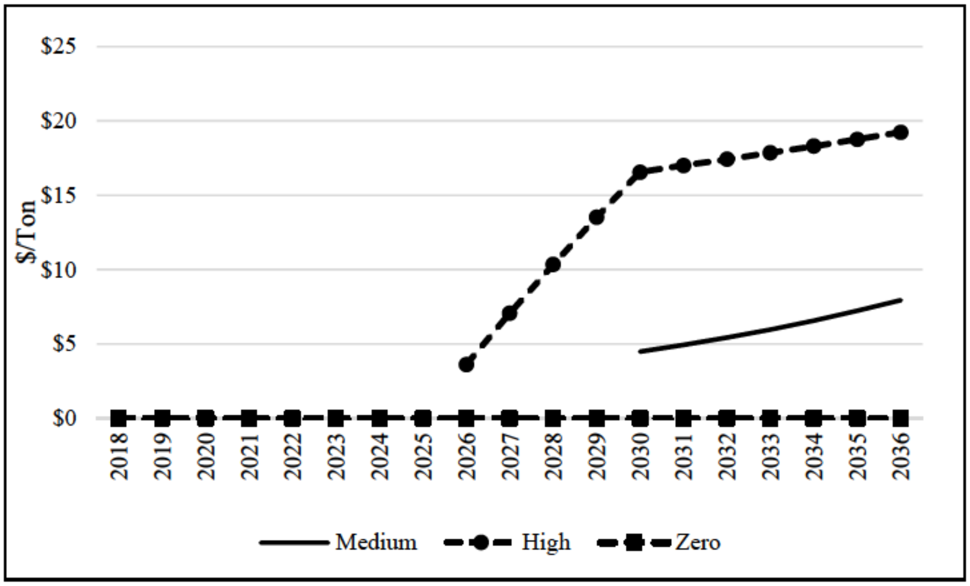
Figure 1. Nominal Natural-Gas Price Scenarios in the February 2018 Analysis



Q. Please describe the CO_2 price assumptions used in the February 2018 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]. 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 CO_2 price assumptions used to analyze the wind repowering project.

Figure 2. Nominal CO_2 Price Assumptions in the February 2018 Analysis



August 2018 Price-Policy Assumptions

Q. What price-policy assumptions did PacifiCorp use in its August 2018 wind repowering analysis?

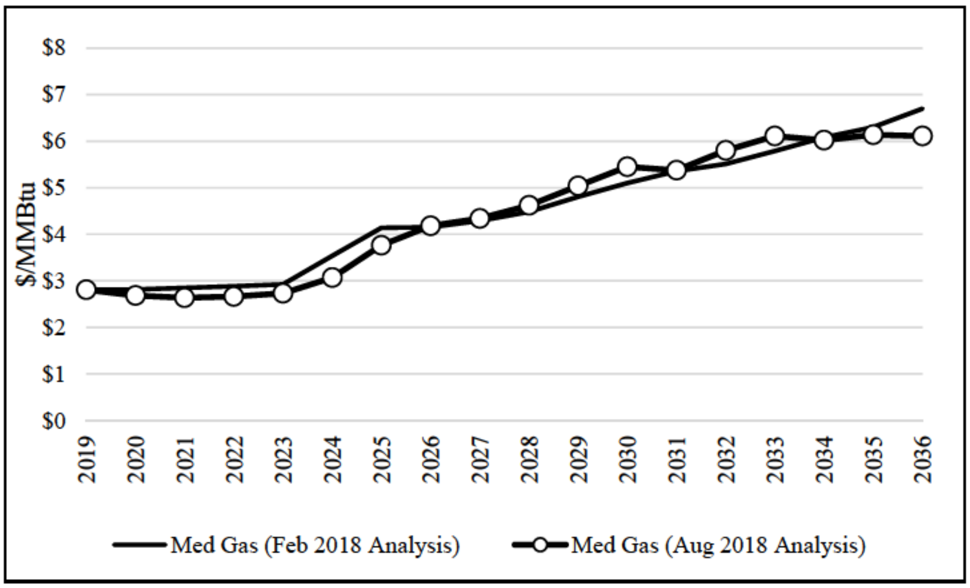
A. In August 2018, PacifiCorp conducted a more targeted wind repowering analysis to understand how the results were impacted by certain assumption updates, which I describe later in my testimony. For this study, therefore, PacifiCorp only updated its medium natural-gas price and CO_2 price assumptions.

Q. Please describe the natural-gas price assumption used in the August 2018 price-policy scenario.

A. The medium-natural-gas price assumption that is paired with medium CO_2 prices reflect natural-gas prices from PacifiCorp's OFPC dated June 29, 2018. This OFPC uses observed forward market prices as of June 29, 2018, for 72 months, followed by a 12-month transition to natural-gas prices based on an updated forecast developed by [redacted].

Figure 3 shows Henry Hub natural-gas price assumptions used in the August 2018 wind repowering analysis alongside the medium natural gas price assumptions used in February 2018 wind repowering analysis. The nominal levelized price over the period 2019 through 2036 from the August 2018 analysis is \$3.97/MMBu, which is down just two percent relative to the \$4.05/MMBtu levelized price from the February 2018 analysis.

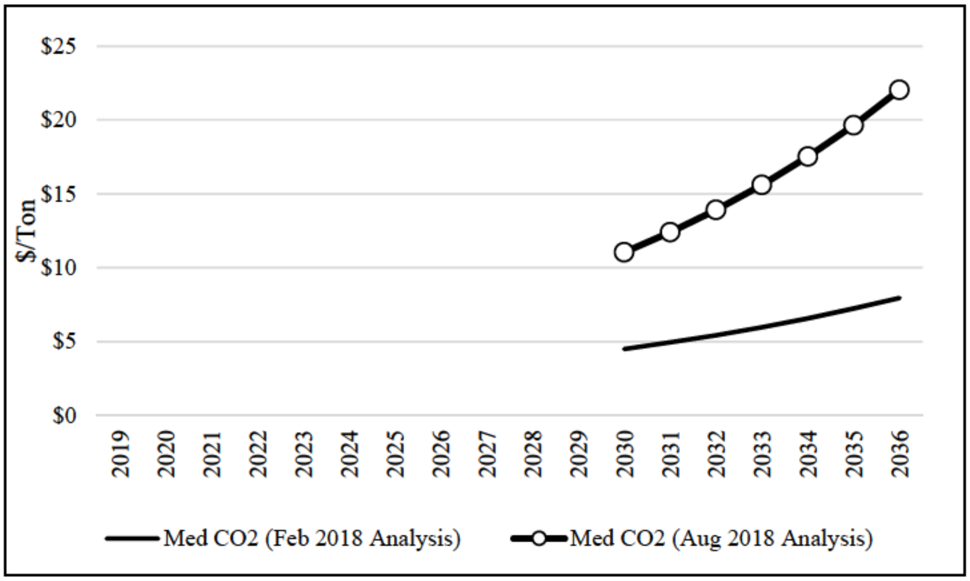
Figure 3. Nominal Natural-Gas Price Assumptions in the August 2018 Analysis Relative to Medium Price Assumptions from the February 2018 Analysis



Q. Please describe the CO_2 price assumption used in the August 2018 price-policy scenario.

A. As with natural-gas prices, the medium CO_2 price assumption is based on a forecast from [redacted]. Figure 4 shows how the CO_2 price assumptions used in the August 2018 wind repowering analysis compares to the medium assumption used in the February 2018 wind repowering analysis. In both instances, the CO_2 price is applied beginning 2030, and while the CO_2 price used in the August 2018 analysis is higher, this is driven by the fact that CO_2 price assumptions used in February 2018 analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. As noted below, this was corrected in the August 2018 analysis, which was modeled in nominal dollars. The CO_2 price assumptions used in the August 2018 analysis applies inflation to determine the prices in nominal dollars.

Figure 4. CO_2 Price Assumptions in the August 2018 Analysis Relative to Medium Price Assumptions from the February 2018 Analysis



Other Assumption Updates in the August 2018 Analysis

Q. Beyond the price-policy assumptions discussed earlier in your testimony, what other assumptions did you update in the August 2018 wind repowering analysis?

A. The August 2018 analysis includes updated hourly market price profiles, updated firm resources, which includes 1,150 MW of new Wyoming wind resource capacity consistent with the final shortlist from the 2017R RFP and inclusion of the Aeolus-to-Bridger/Anticline transmission line, updated proxy resource costs for new wind and solar resources, and updated inflation rate assumptions. The August 2018 analysis also reflects an updated load forecast, which was refreshed after PacifiCorp filed its 2017 IRP Update.

Table 1. Updated Assumptions in the August 2018 Analysis Relative to Assumptions from the February 2018 Analysis

Description	February 2018 Analysis (Pre-Approval Proceedings)	August 2018 Analysis
Load Forecast	August 2017	June 2018
Hourly Price Profile	PowerDex Scalar Method	CAISO Day-Ahead Method
Energy Vision 2020	No New Wind and Transmission	1,150 MW of Wyoming wind and the Aeolus-to-Bridger/Anticline Transmission Line
Other Resources	2017 IRP	2017 IRP Update plus Executed and Planned Solar PPAs
Annual Inflation Rate	2.22%	2.27%
Proxy Resource Costs	2017 IRP	2017 IRP Update

FEBRUARY 2018 WIND REPOWERING ANALYSIS

Project-by-Project Results

Q. What price-policy scenarios were used in the project-by-project analysis?

A. PacifiCorp used two price-policy scenarios—the low natural-gas and zero CO_2 price-policy scenario and the medium natural-gas and medium CO_2 price-policy scenario. Based on the results of these two price-policy scenarios, the company determined which individual projects are expected to provide net customer benefits, and then these projects were analyzed under all price-policy scenarios.

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming medium natural-gas and medium CO_2 price-policy assumptions.

A. Table 2 summarizes the PVRR(d) results for each wind facility. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying medium natural-gas and medium CO_2 price-policy assumptions, benefits from repowering the Leaning Juniper wind facility are equal to costs. All other wind facilities are projected to deliver net benefits.

Table 2. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions (2017$ million), February 2018

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($25)	($21)	($23)
Glenrock 3	($8)	($7)	($7)
Seven Mile Hill 1	($33)	($28)	($29)
Seven Mile Hill 2	($7)	($7)	($7)
High Plains	($17)	($13)	($13)
McFadden Ridge	($5)	($4)	($4)
Dunlap Ranch	($30)	($26)	($27)
Rolling Hills	($12)	($9)	($10)
Leaning Juniper	($0)	($0)	($0)
Marengo 1	($35)	($33)	($34)
Marengo 2	($15)	($14)	($15)
Goodnoe Hills	($18)	($18)	($19)
Total	($205)	($180)	($189)

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 3 summarizes the PVRR(d) results for each wind facility. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying low natural-gas and zero CO_2 price-policy assumptions, costs from repowering the Leaning Juniper wind facility are slightly higher than the benefits. All other wind facilities are projected to deliver net benefits.

Table 3. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions (2017$ million), February 2018

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($21)	($21)	($22)
Glenrock 3	($7)	($6)	($6)
Seven Mile Hill 1	($28)	($28)	($29)
Seven Mile Hill 2	($6)	($6)	($6)
High Plains	($12)	($9)	($10)
McFadden Ridge	($4)	($3)	($3)
Dunlap Ranch	($25)	($22)	($24)
Rolling Hills	($9)	($7)	($7)
Leaning Juniper	$6	$3	$4
Marengo 1	($27)	($25)	($26)
Marengo 2	($11)	($10)	($11)
Goodnoe Hills	($13)	($15)	($15)
Total	($157)	($149)	($156)

Project-by-Project Annual Revenue Requirement Price-Policy Results

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

A. Table 4 summarizes the PVRR(d) results for each wind facility calculated from the change in annual nominal revenue requirement through 2050 for both price-policy scenarios. Unlike the results summarized in Tables 2 and 3, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering under the medium natural-gas and medium CO_2 price-policy scenario and all facilities show net benefits under the low-natural-gas and zero CO_2 price-policy scenario, except for the Leaning Juniper wind facility, where the benefits are equal to the costs.

Table 4. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering (2017$ million), February 2018

Wind Facility	Medium Natural-Gas and Medium CO_2	Low Natural-Gas and Zero CO_2
Glenrock 1	($33)	($33)
Glenrock 3	($11)	($6)
Seven Mile Hill 1	($41)	($40)
Seven Mile Hill 2	($10)	($6)
High Plains	($22)	($6)
McFadden Ridge	($7)	($2)
Dunlap Ranch	($39)	($23)
Rolling Hills	($15)	($5)
Leaning Juniper	($8)	($0)
Marengo 1	($50)	($22)
Marengo 2	($20)	($7)
Goodnoe Hills	($26)	($19)
Total	($282)	($170)

Q. The project-by-project results vary by wind facility, and some wind facilities appear to show relatively small PVRR(d) benefits. Have you calculated the net benefits of the wind repowering project taking into account the size of each wind facility?

A. Yes. The magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows a $7 million benefit when repowered (using medium natural-gas and medium CO_2 price-policy assumptions)—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is approximately 14 percent of the $50 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, the capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the capacity of Marengo I (140.4 MW). Similarly, the expected energy output after repowering McFadden Ridge (approximately 117 GWh per year) is approximately 24 percent of the expected energy output after repowering Marengo I (approximately 488 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental MWh expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 5 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. When using medium natural-gas and medium CO_2 price-policy assumptions, Table 5 shows the Seven Mile Hill II facility produces the largest net benefit per incremental MWh ($36/MWh), and Leaning Juniper produces the smallest net benefit per incremental MWh ($7/MWh).

Table 5. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering (2017$/MWh), February 2018

Wind Facility	Medium Natural-Gas and Medium CO_2	Low Natural-Gas and Zero CO_2
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$16/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$23/MWh
High Plains	$17/MWh	$5/MWh
McFadden Ridge	$17/MWh	$5/MWh
Dunlap Ranch	$28/MWh	$17/MWh
Rolling Hills	$19/MWh	$7/MWh
Leaning Juniper	$7/MWh	$0/MWh
Marengo 1	$25/MWh	$11/MWh
Marengo 2	$21/MWh	$8/MWh
Goodnoe Hills	$26/MWh	$18/MWh
Weighted Average	$23/MWh	$14/MWh

Q. Is there an upside to the project-by-project PVRR(d) results?

A. Yes. The project-by-project results do not reflect the potential value of RECs that will be generated by the incremental energy output from each facility. For instance, as applied to the Leaning Juniper project discussed above, present-value net customer benefits would increase by approximately $1.1 million (approximately 14 percent of the PVRR(d) benefits under the medium natural-gas and medium CO_2 price-policy scenario as shown in Table 4) for every dollar assigned to the incremental RECs that will be generated from this facility. Moreover, as noted early in my testimony, the CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the medium natural-gas, medium CO_2 price-policy scenario are conservative.

Project-wide SO and PaR Price-Policy Results

Q. Please summarize the PVRR(d) results for the full scope of the wind repowering project as calculated from the SO model and PaR through 2036 among all nine price-policy scenarios.

A. Table 6 summarizes the PVRR(d) results for each price-policy scenario for the full scope of the wind repowering project. The PVRR(d) between cases with and without the repowering project are shown for the SO model and for PaR. The data used to calculate the PVRR(d) results shown in Table 6 are provided as Exhibit PAC/303.

Table 6. Project-Wide SO Model and PaR PVRR(d) (Benefit)/Cost of the Wind Repowering Projects (2017$ million), February 2018

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($159)	($141)	($148)
Low Gas, Medium CO_2	($158)	($139)	($146)
Low Gas, High CO_2	($183)	($165)	($173)
Medium Gas, Zero CO_2	($201)	($171)	($180)
Medium Gas, Medium CO_2	($204)	($180)	($189)
Medium Gas, High CO_2	($215)	($193)	($203)
High Gas, Zero CO_2	($257)	($234)	($246)
High Gas, Medium CO_2	($260)	($248)	($260)
High Gas, High CO_2	($273)	($240)	($252)

Over a 20-year period, the wind repowering project reduces customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and

PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $180 million, when derived from PaR stochastic-mean results, and $204 million, when derived from SO model results.

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

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

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

A. Yes. The PVRR(d) results presented in Table 6 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered facilities through 2036. Quantifying the potential upside associated with incremental REC revenues is intended simply to communicate that the net benefits from the repowering project would improve if the incremental RECs can be monetized in the market or if those RECs are used to reduce incremental costs associated with meeting state renewable portfolio standard targets. Moreover, as noted earlier in my testimony, the CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

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.

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 show slightly greater net benefits than those calculated from the stochastic-mean PVRR(d) results. This indicates that the wind repowering project, which provides incremental zero-fuel-cost energy, provides incremental benefits in reducing the impact of 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.

Project-Wide Annual Revenue Requirement Price-Policy Results

Q. Please summarize the PVRR(d) results for the full scope of the wind repowering project as calculated from the change in annual revenue requirement through 2050.

A. Table 7 summarizes the PVRR(d) results for the full scope of the wind repowering project for each price-policy scenario calculated from the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that were used to calculate the PVRR(d) results shown in Table 7 are provided as Exhibit PAC/304.

Table 7. Project-Wide Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering (2017$ million), February 2018

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($127)
Low Gas, Medium CO_2	($121)
Low Gas, High CO_2	($223)
Medium Gas, Zero CO_2	($224)
Medium Gas, Medium CO_2	($273)
Medium Gas, High CO_2	($321)
High Gas, Zero CO_2	($389)
High Gas, Medium CO_2	($386)
High Gas, High CO_2	($466)

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 $121 million in the low natural-gas and medium CO_2 price-policy scenario to $466 million in the high natural-gas and high CO_2 price-policy scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits are $273 million.

Q. What are the gross customer benefits of the repowering project and how do those gross benefits compare to project costs?

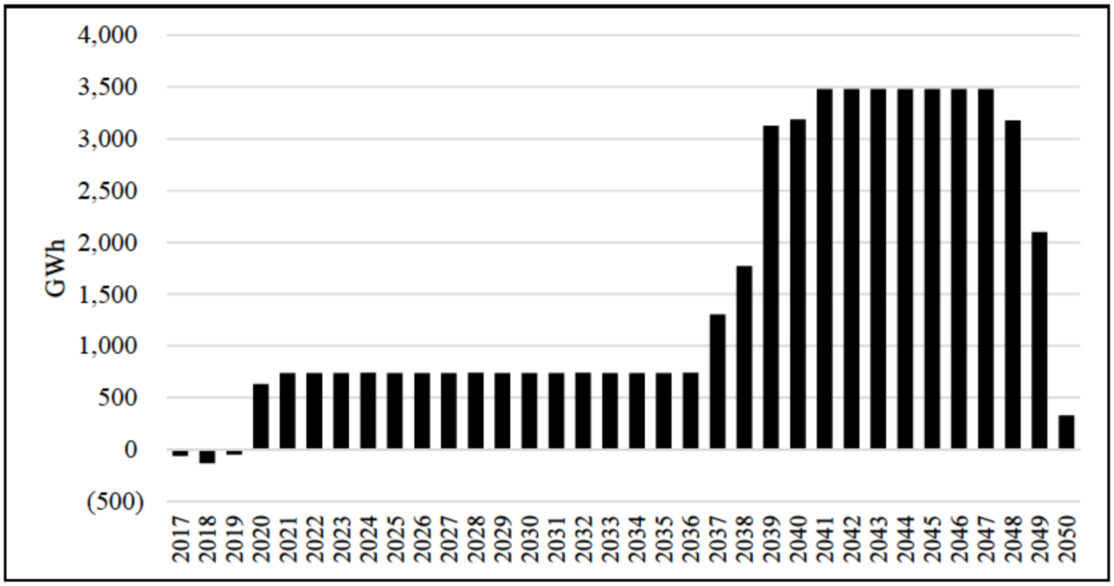
A. Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value project costs totaling $1.01 billion.

Q. What causes the increase in PVRR(d) benefits for many of the price-policy scenarios when calculated from 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 5 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 738 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 3,478 GWh.

Figure 5. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh), February 2018



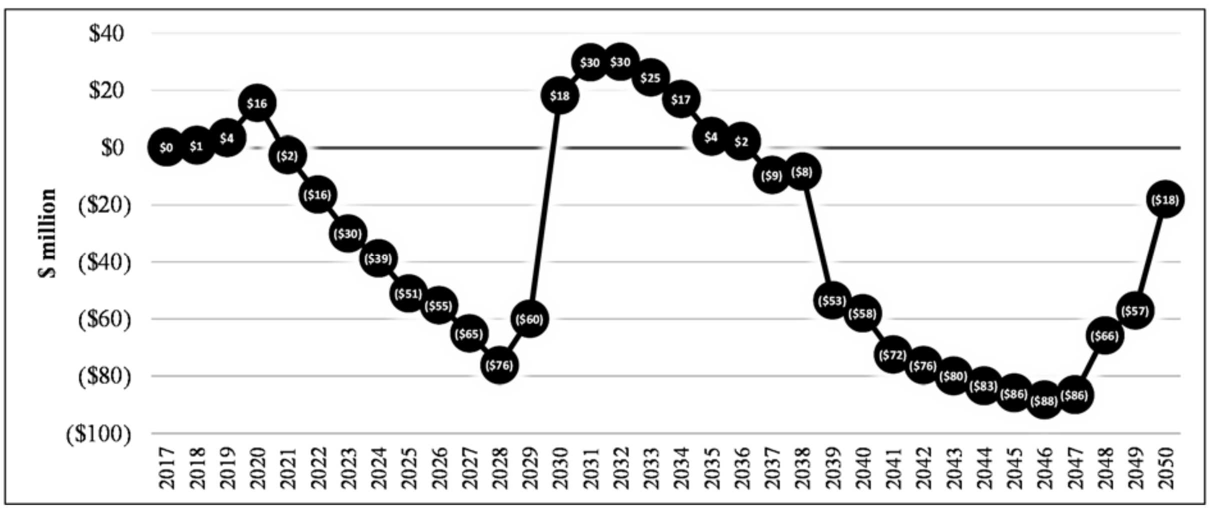
Q. Is there additional potential upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?

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 7 do not reflect the potential value of RECs produced by the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $12 million for every dollar assigned to the incremental RECs that will be generated from the wind repowering project through 2050. Moreover, as noted earlier, the CO_2 price assumptions used in the February 2018 economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

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

A. Figure 6 shows the change in nominal revenue requirement due to the wind repowering project for the medium natural-gas, medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects project costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against system impacts from the wind repowering project, 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 6. Total-System Annual Revenue Requirement
With the Wind Repowering Project (Benefit)/Cost (2017$ million), February 2018**



As this chart shows, the wind repowering project generates substantial near-term customer benefits and continues to contribute to customer benefits over the long term. 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 an increase in revenue requirement in 2017 and 2018 ($1 million to $4 million, total system). In the February 2018 analysis, all of the facilities were assumed to be repowered in 2019, except the Dunlap facility, which was assumed to be repowered toward the end of 2020.[4] 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, and from 2021 through 2028, annual revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. The reduction in annual revenue requirement is $76 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.

Q. Did you evaluate how wind repowering benefits assumed beyond 2036 affect the PVRR(d) results calculated from the change in annual nominal revenue requirement through 2050?

A. Yes. The point of extrapolating results beyond 2036 is to capture the benefits from the significant increase in the expected annual energy output from the repowered wind facilities beyond the period in which the existing wind facilities would have

[4] Based on more current information, both the Dunlap and Glenrock III facilities will be repowered in 2020. As noted elsewhere in my testimony, these facilities are therefore not included in this Schedule 202 filing for 2019.

otherwise reached the end of their lives. While the methodology used in my analysis is valid, the value of this incremental energy can be evaluated in different ways.

Table 8 summarizes how the PVRR(d) results through 2050 would change if flat market prices at the Palo Verde (PV) market from the December 29, 2017 OFPC were used as the basis to evaluate the value of incremental energy from wind repowering over the 2037-through-2050 time frame. Recognizing there is both upside and downside price risk to the value of this energy, I assume different levels of PV prices—70 percent of the PV forward curve, 100 percent of the PV forward curve, and 130 percent of the PV forward curve. PacifiCorp's December 29, 2017 OFPC includes forward prices through 2042. Conservatively, I assume no escalation in PV prices beyond 2042 for each of these scenarios. Each of these scenarios is shown alongside the $273 million PVRR(d) net benefit when incremental energy from repowering beyond 2036 is calculated from system modeling results over the 2028 through 2036 time frame.

Table 8. Long-Term Benefit Sensitivity, February 2018

Source of 2037-2050 Benefits	Nominal Levelized Benefit from 2037-2050 ($/MWh)	Annual Revenue Requirement PVRR(d) (Benefit)/Cost ($ million)
2027-2036 System Modeling	$59.08	($273)
70% of PV	$49.49	($213)
100% of PV	$70.70	($351)
130% of PV	$91.92	($489)

This analysis demonstrates that regardless of the methodology used to extend wind repowering benefits to 2050, the PVRR(d) result shows significant customer savings. If the incremental energy is valued at the PV forward curve, the PVRR(d) benefits of the wind repowering project are $351 million, which is $78 million higher than the methodology used in my analysis.

New Wind and Transmission Sensitivity

Q. Did PacifiCorp produce any sensitivities on its economic analysis of the wind repowering project?

A. Yes. In the February 2018 analysis, PacifiCorp developed a sensitivity to quantify how the net benefits of wind repowering are affected when combined with 1,170 MW of new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission included in the company's 2017 IRP.[5] This sensitivity was based on the assumption that the new wind and transmission would be operational by the end of 2020.

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

A. Table 9 summarizes the PVRR(d) results for the new wind sensitivity that assumes wind repowering is implemented in combination with adding 1,170 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the base repowering study presented above in which wind repowering was evaluated without the new wind and transmission

[5] The 2017 IRP assumed 1,100 MW of new Wyoming wind by the end of 2020. After filing the 2017 IRP, PacifiCorp issued its 2017R RFP and initially identified 1,170 MW of new Wyoming wind to the final shortlist, which served as the basis for this sensitivity. PacifiCorp later updated its 2017R RFP final shortlist to include 1,150 MW of new Wyoming wind.

Table 9. New Wind and Aeolus-to-Bridger/Anticline Sensitivity (Benefit)/Cost of Wind Repowering (2017$ million), February 2018

	Sensitivity (Repowering + New Wind & Trans.) PVRR(d)	Base Study (Repowering) PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($532)	($204)	($328)
PaR Stochastic Mean	($466)	($180)	($286)
PaR Risk Adjusted	($489)	($189)	($300)
Low Gas, Zero CO_2			
SO Model	($301)	($159)	($142)
PaR Stochastic Mean	($300)	($141)	($159)
PaR Risk Adjusted	($315)	($148)	($167)

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

AUGUST 2018 WIND REPOWERING ANALYSIS

Project-by-Project SO and PaR Model Price-Policy Results

Q. Please summarize the scope of the approach taken in the August 2018 analysis, relative to the February 2018 analysis, including the price-policy scenarios used.

A. For the August 2018 analysis, PacifiCorp performed a project-by-project economic analysis that was updated to account for more current modeling assumptions, using the same basic methodology used in the February 2018 analysis: SO model and PaR studies through 2036 (levelized capital and nominal treatment of PTCs); and nominal revenue requirement analysis through 2050 (nominal capital and nominal treatment of

PTCs). PacifiCorp performed the updated analysis in August 2018 for each facility using medium natural gas and medium CO_2 price-policy assumptions.

For Leaning Juniper, PacifiCorp also performed an updated analysis in August 2018 using the most conservative low natural gas and zero CO_2 price-policy assumptions. This additional price-policy scenario was analyzed for the Leaning Juniper facility because its cost-and-performance assumptions had improved relative to the February 2018 analysis where Leaning Juniper presented the lowest customer net benefits relative to other wind facilities.

Q. How did the cost-and-performance assumptions change for Leaning Juniper in the August 2018 analysis relative to the February 2018 analysis?

A. After evaluating alternative equipment suppliers, the capital cost required to repower Leaning Juniper was reduced by approximately [redacted] from [redacted] to [redacted] and the expected increase in annual energy output increased from [redacted] percent to [redacted] percent.

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming medium natural-gas and medium CO_2 price-policy assumptions.

A. Table 10 summarizes the PVRR(d) results for each wind facility.[6] The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When

[6] With the passage of time between the February 2018 and August 2018 analyses, PVRR(d) results from the August 2018 analysis are discounted back to 2018 dollars. Results from the February 2018 analysis are discounted back to 2017 dollars.

applying medium natural-gas and medium CO_2 price-policy assumptions, all wind facilities are projected to deliver net benefits.

Table 10. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions (2018$ million); August 2018

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($29)	($24)	($31)
Glenrock 3	($10)	($8)	($11)
Seven Mile Hill 1	($40)	($31)	($39)
Seven Mile Hill 2	($9)	($8)	($9)
High Plains	($23)	($14)	($21)
McFadden Ridge	($7)	($5)	($7)
Dunlap Ranch	($37)	($28)	($37)
Rolling Hills	($16)	($11)	($16)
Leaning Juniper	($10)	($10)	($10)
Marengo 1	($44)	($33)	($43)
Marengo 2	($20)	($15)	($20)
Goodnoe Hills	($24)	($20)	($26)

Q. How do the August 2018 results in Table 10 compare with February 2018 results assuming medium natural-gas and medium CO_2 price-policy assumptions?

A. Using the medium natural-gas and medium CO_2 price-policy assumptions, the August 2018 project-by-project PVRR(d) results calculated from the SO and PaR models through 2036 are similar to, and generally improve upon, projected customer benefits relative to the February 2018 project-by-project PVRR(d) results.[7] Table 11 displays the two sets of analyses side by side. These results confirm that with updated

[7] As discussed further below, a particularly notable change is evident for Leaning Juniper. This facility was projected in February 2018 to provide net zero customer benefits, but with improved cost-and-performance assumptions applied in the August 2018 analysis is projected to provide $10 million in net positive customer benefits.

assumptions, the conclusions from the February 2018 study—implementing the repowering project will provide substantial customer benefits—remain valid.

Table 11. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions ($ million); February and August 2018

Wind Facility	SO Model PVRR(d)		PaR Stochastic-Mean PVRR(d)		PaR Risk-Adjusted PVRR(d)	
	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)
Glenrock 1	($25)	($29)	($21)	($24)	($23)	($31)
Glenrock 3	($8)	($10)	($7)	($8)	($7)	($11)
Seven Mile Hill 1	($33)	($40)	($28)	($31)	($29)	($39)
Seven Mile Hill 2	($7)	($9)	($7)	($8)	($7)	($9)
High Plains	($17)	($23)	($13)	($14)	($13)	($21)
McFadden Ridge	($5)	($7)	($4)	($5)	($4)	($7)
Dunlap Ranch	($30)	($37)	($26)	($28)	($27)	($37)
Rolling Hills	($12)	($16)	($9)	($11)	($10)	($16)
Leaning Juniper	($0)	($10)	($0)	($10)	($0)	($10)
Marengo 1	($35)	($44)	($33)	($33)	($34)	($43)
Marengo 2	($15)	($20)	($14)	($15)	($15)	($20)
Goodnoe Hills	($18)	($24)	($18)	($20)	($19)	($26)

Q. Please summarize the PVRR(d) results for the Leaning Juniper facility calculated from the SO model and PaR through 2036 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 12 summarizes the PVRR(d) results for the Leaning Juniper facility when applying low natural-gas and zero CO_2 price-policy assumptions. Results, which represent the PVRR(d) between cases with and without repowering the Leaning Juniper facility, are shown alongside those reported from the February 2018 analysis. The PVRR(d) results in Table 12 are from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. Under this most conservative price-policy scenario, the Leaning Juniper facility is still projected to deliver net benefits, and driven by improved cost-and-performance assumptions, these net benefits improve relative to the February 2018 PVRR(d) results. These results confirm that with updated assumptions, implementing the entire repowering project, including at the Leaning Juniper facility, will provide customer benefits and is therefore prudent.

Table 12. Leaning Juniper SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions ($ million); February and August 2018

Wind Facility	SO Model PVRR(d)		PaR Stochastic-Mean PVRR(d)		PaR Risk-Adjusted PVRR(d)	
	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)
Leaning Juniper	$6	($5)	$3	($4)	$4	($4)

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

A. Yes. As is the case for the February 2018 analysis, the PVRR(d) results presented in Tables 10 and 12 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities.

Project-by-Project Annual Revenue Requirement Price-Policy Results

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

A. Table 13 summarizes the PVRR(d) results for each wind facility calculated from the change in annual nominal revenue requirement through 2050 for the medium natural-gas and medium CO_2 price-policy scenario. Unlike the results summarized in Table 10, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering under the medium natural-gas and medium CO_2 price-policy scenario.

Table 13. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering (2018$ million), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost
Glenrock 1	($35)
Glenrock 3	($10)
Seven Mile Hill 1	($43)
Seven Mile Hill 2	($9)
High Plains	($19)
McFadden Ridge	($5)
Dunlap Ranch	($39)
Rolling Hills	($15)
Leaning Juniper	($21)
Marengo 1	($46)
Marengo 2	($17)
Goodnoe Hills	($25)

Q. How do the August 2018 results in Table 13 compare with the February 2018 analysis assuming medium natural-gas and medium CO_2 price-policy assumptions?

A. Using the medium natural-gas and medium CO_2 price-policy assumptions, the August 2018 project-by-project PVRR(d) results calculated from change in annual nominal revenue requirement through 2050 are similar to the February 2018 results. Table 14 displays the two sets of analyses side by side. These results confirm that with updated assumptions, the conclusions from the February 2018 study—implementing the repowering project will provide substantial customer benefits—remain valid.

Table 14. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; February and August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost	
	February 2018 (2017$)	August 2018 (2018$)
Glenrock 1	($33)	($35)
Glenrock 3	($11)	($10)
Seven Mile Hill 1	($41)	($43)
Seven Mile Hill 2	($10)	($9)
High Plains	($22)	($19)
McFadden Ridge	($7)	($5)
Dunlap Ranch	($39)	($39)
Rolling Hills	($15)	($15)
Leaning Juniper	($8)	($21)
Marengo 1	($50)	($46)
Marengo 2	($20)	($17)
Goodnoe Hills	($26)	($25)

Q. Please summarize the PVRR(d) results for the Leaning Juniper facility calculated from the change in annual revenue requirement through 2050 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 15 summarizes the PVRR(d) results for the Leaning Juniper facility when applying low natural-gas and zero CO_2 price-policy assumptions. Results, which represent the PVRR(d) between cases with and without repowering the Leaning Juniper facility, are shown alongside those reported from the February 2018 analysis. The PVRR(d) results in Table 15 are based on system modeling results from the change in annual revenue requirement through 2050. Under this most conservative price-policy scenario, the Leaning Juniper facility is still projected to deliver net benefits, and driven by improved cost-and-performance assumptions, these net benefits improve relative to the February 2018 PVRR(d) results. These results confirm that with updated assumptions, implementing the entire repowering project, including at the Leaning Juniper facility, will provide customer benefits and is therefore prudent.

Table 15. Leaning Juniper Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million), with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions; February and August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost	
	February 2018 (2017$)	August 2018 (2018$)
Leaning Juniper	($0)	($4)

Q. Have you calculated the net benefits of the wind repowering project taking into account the size of each wind facility?

A. Yes. As discussed above, the metric of nominal levelized net benefit per incremental MWh expected after the facility is repowered captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 16 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering each wind facility. When using medium natural-gas and medium CO_2 price-policy assumptions, Table 16 shows the Glenrock 1, Seven Mile Hill 1, and Seven Mile Hill 2 facilities produce the largest net benefit per incremental MWh

($29/MWh), and McFadden Ridge produces the smallest net benefit per incremental MWh ($12/MWh).

Table 16. Project-by-Project Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering (2018$/MWh), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; August 2018

Wind Facility	Nom. Lev. $/MWh
Glenrock 1	$29/MWh
Glenrock 3	$25/MWh
Seven Mile Hill 1	$29/MWh
Seven Mile Hill 2	$29/MWh
High Plains	$14/MWh
McFadden Ridge	$12/MWh
Dunlap Ranch	$27/MWh
Rolling Hills	$17/MWh
Leaning Juniper	$17/MWh
Marengo 1	$21/MWh
Marengo 2	$17/MWh
Goodnoe Hills	$23/MWh

Q. How do the August 2018 results in Table 16 compare with the prior analysis in February 2018 assuming medium natural-gas and medium CO_2 price-policy assumptions?

A. Using the medium natural-gas and medium CO_2 price-policy assumptions, the August 2018 project-by-project metrics for nominal levelized net benefit per incremental MWh expected after the facility is repowered are similar to the February 2018 results under the same price-policy scenario. Table 17 displays the two sets of analyses side by side. These results confirm that with updated assumptions, the conclusions from the February 2018 study—implementing the repowering project will provide substantial customer benefits—remain valid.

Table 17. Project-by-Project Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; Feb. and Aug. 2018

Wind Facility	Nom. Lev. $/MWh	
	February 2018	August 2018
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$25/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$29/MWh
High Plains	$17/MWh	$14/MWh
McFadden Ridge	$17/MWh	$12/MWh
Dunlap Ranch	$28/MWh	$27/MWh
Rolling Hills	$19/MWh	$17/MWh
Leaning Juniper	$7/MWh	$17/MWh
Marengo 1	$25/MWh	$21/MWh
Marengo 2	$21/MWh	$17/MWh
Goodnoe Hills	$26/MWh	$23/MWh

Q. Is there an upside to the project-by-project PVRR(d) results?

A. Yes. As is the case for the February 2018 analysis, these project-by-project results do not reflect the potential value of RECs that will be generated by the incremental energy output from each facility.

CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp’s analysis supports repowering approximately 999.1 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington, which includes the nine facilities included in this 2019 Schedule 202 filing. The repowered wind facilities will qualify for an additional 10 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 project 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-wide costs.

Q. What do you recommend?

A. As supported by the economic analyses described in my testimony, I recommend the Commission determine that the decision to repower certain wind facilities in 2019 is prudent and approve this Schedule 202 filing requesting the proposed ratemaking treatment for the new costs of the wind repowering project.

Q. Does this conclude your direct testimony?

A. Yes.

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Docket No. UE 352
Exhibit PAC/301
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Wind Facility Data

December 2018

[redacted]

Existing Wind Prior to Repowering

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

Repowered Wind

	Capacity (MW)	LGIA Limited Capacity[1] (MW)	LGIA Limited Energy (MWh)	LGIA Limited Capacity Factor	Repower Capital Investment ($m)	Date PTC Ends	End-of-Life Date	Repower Date
Glenrock 1	112.0	99.0	369,723	42.6%	[redacted]	9/30/2029	10/1/2049	10/1/2019
Glenrock 3	44.3	39.0	136,864	40.1%		9/30/2029	10/1/2049	10/1/2019
Seven Mile Hill 1	110.9	99.0	417,258	48.1%		6/30/2029	7/1/2049	7/1/2019
Seven Mile Hill 2	22.8	19.5	87,480	51.2%		6/30/2029	7/1/2049	7/1/2019
High Plains	115.5	99.0	382,400	44.1%		10/31/2029	11/1/2049	11/1/2019
McFadden Ridge	33.3	28.5	116,644	46.7%		10/31/2029	11/1/2049	11/1/2019
Dunlap Ranch	129.5	111.0	476,749	49.0%		11/30/2030	12/1/2050	12/1/2020
Rolling Hills	107.5	99.0	319,022	36.8%		9/30/2029	10/1/2049	10/1/2019
Leaning Juniper	110.6	100.5	296,590	33.7%		9/30/2029	10/1/2049	10/1/2019
Marengo 1	156.0	156.0	488,207	35.7%		10/31/2029	11/1/2049	11/1/2019
Marengo 2	78.0	78.0	232,424	34.0%		10/31/2029	11/1/2049	11/1/2019
Goodnoe Hills	103.4	94.0	283,696	34.5%		9/30/2029	10/1/2049	10/1/2019
Total	1,123.6	1,022.5	3,607,057	40.3%	$0			

[1] Marengo 1 and 2 include increased interconnection capability based on the completion of recent transmission studies.

[redacted]

Run-Rate Capital

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

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

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

Run-Rate Operations and Maintenance Expense

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
All Repowered Projects	$0.0	$0.0	$3.9	$12.1	$12.8	$9.6	$9.5	$9.4	$9.2	$9.1	$9.0	$8.8

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	$5.9	$2.2	$1.2	$1.2	$1.2	$1.2	$1.3	$2.1	$5.5	$13.7	$28.2	$29.5

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$32.3	$33.1	$33.8	$34.6	$35.4	$36.2	$37.1	$37.9	$29.9	$2.6

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Docket No. UE 352
Exhibit PAC/302
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

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Henry Hub Natural Gas Price Forecasts in February 2018 Analysis

December 2018

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

Year	Dec 29, 2017 OFPC	Adopted Medium IHS (CERA) Base	Adopted High IHS (CERA) High - Adjusted	Adopted Low (PIRA Low)	PIRA Base	PIRA High	IHS (CERA) High	EIA Low Price	EIA High Price	IHS (CERA) Low	Lowest Price	Highest Price	Range
2018	$2.85	[redacted]						$3.24	$3.83	[redacted]	$2.56	$3.89	$1.33
2019	$2.81							$3.75	$4.71		$2.60	$4.71	$2.10
2020	$2.82							$3.86	$5.90		$2.47	$5.90	$3.43
2021	$2.85							$3.62	$6.44		$2.33	$6.44	$4.11
2022	$2.89							$3.56	$7.24		$2.32	$7.24	$4.92
2023	$2.93							$3.71	$7.74		$2.54	$7.74	$5.20
2024	$3.49							$3.94	$8.19		$2.71	$8.19	$5.48
2025	$4.09							$4.14	$8.76		$2.87	$8.76	$5.89
2026	$4.15							$4.37	$9.41		$3.03	$9.41	$6.38
2027	$4.29							$4.63	$9.86		$3.04	$9.86	$6.82
2028	$4.49							$4.96	$10.30		$3.20	$10.30	$7.09
2029	$4.80							$5.08	$10.72		$3.36	$10.72	$7.36
2030	$5.10							$5.03	$11.02		$3.49	$11.02	$7.53
2031	$5.35							$4.89	$11.89		$3.61	$11.89	$8.28
2032	$5.51							$4.90	$12.45		$3.72	$12.45	$8.73
2033	$5.79							$4.97	$12.71		$3.75	$12.71	$8.96
2034	$6.08							$5.07	$12.96		$3.84	$12.96	$9.12
2035	$6.30							$5.15	$13.24		$3.93	$13.24	$9.32
2036	$6.70							$5.21	$14.06		$4.01	$14.06	$10.05

[redacted]

Docket No. UE 352
Exhibit PAC/303
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

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Exhibit Accompanying Direct Testimony of Rick T. Link

SO Model Annual Results from the February 2018 Analysis

December 2018

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($155)	$1	$3	$1	($13)	($16)	($16)	($17)	($18)	($18)	($19)	($20)	($22)	($23)	($25)	($25)	($25)	($26)	($27)	($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 DSM	($5)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($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	($159)	$58	$62	$37	($51)	($73)	($72)	($76)	($75)	($79)	($78)	($82)	($83)	($56)	$34	$53	$54	$55	$56	$57	$59

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($145)	$1	$3	$1	($13)	($16)	($16)	($17)	($18)	($19)	($19)	($20)	($23)	($23)	($26)	($25)	($26)	($26)	($28)	($5)	$3
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($2)	($1)	$2	$2
Change in DSM	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)
Change in System Fixed Cost	($12)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($15)	($28)
Net (Benefit)/Cost	($158)	$58	$62	$37	($51)	($73)	($72)	($76)	($75)	($79)	($78)	($82)	($83)	($56)	$32	$52	$53	$53	$54	$66	$62

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($166)	$1	$3	$1	($13)	($16)	($16)	($17)	($17)	($18)	($19)	($20)	($24)	($27)	($28)	($29)	($28)	($29)	($31)	($31)	($30)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($2)	($3)	($4)	($5)	($6)	($5)	($4)	($5)	($8)
Change in DSM	($9)	$0	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)
Change in System Fixed Cost	$7	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	$3	$3	$3	$3	$2	$2	$2	$4
Net (Benefit)/Cost	($183)	$58	$62	$37	($51)	($73)	($72)	($76)	($76)	($80)	($81)	($86)	($88)	($61)	$27	$46	$47	$48	$49	$50	$52

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($210)	$1	$3	$1	($13)	($17)	($18)	($18)	($20)	($22)	($22)	($23)	($26)	($29)	($32)	($34)	($42)	($46)	($48)	($50)	($60)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($12)	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Change in System Fixed Cost	$20	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$13	$10	$11	$11	$20
Net (Benefit)/Cost	($201)	$58	$62	$37	($52)	($75)	($75)	($78)	($79)	($84)	($83)	($87)	($88)	($63)	$26	$43	$49	$45	$44	$45	$45

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($185)	$1	$3	$1	($14)	($18)	($18)	($19)	($21)	($23)	($23)	($24)	($26)	($30)	($34)	($36)	($48)	($36)	($24)	($14)	($15)
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	($6)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	($14)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$1	$1	$1	$16	($2)	($16)	($28)	($28)
Net (Benefit)/Cost	($204)	$58	$62	$37	($52)	($75)	($74)	($78)	($78)	($84)	($82)	($87)	($88)	($63)	$24	$42	$46	$43	$43	$43	$43

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($215)	$1	$3	$1	($13)	($17)	($18)	($19)	($20)	($23)	($23)	($26)	($28)	($39)	($49)	($53)	($56)	($36)	($35)	($29)	($29)
Change in Emissions	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($2)	($3)	($7)	($4)	($2)	($2)	($0)	($3)	($2)	($2)
Change in DSM	($8)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($1)	($2)	($1)	($1)
Change in System Fixed Cost	$19	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$18	$19	$20	$22	($4)	($3)	($15)	($18)
Net (Benefit)/Cost	($215)	$58	$62	$37	($52)	($75)	($74)	($78)	($78)	($84)	($84)	($91)	($93)	($62)	$23	$42	$42	$40	$41	$38	$37

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($141)	$1	$4	$1	($19)	($21)	($23)	($8)	($9)	($10)	($10)	($11)	($11)	($12)	($16)	($15)	($17)	($41)	($41)	($42)	($39)
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)	($0)	$0	$0	$0	$0	$1	$1	$1	$1	$1	$1
Change in System Fixed Cost	($119)	($0)	($0)	$0	($0)	($0)	$0	($23)	($24)	($24)	($25)	($25)	($26)	($25)	($23)	($25)	($24)	($1)	($3)	($3)	($8)
Net (Benefit)/Cost	($257)	$58	$63	$37	($57)	($78)	($79)	($90)	($90)	($94)	($93)	($97)	($97)	($69)	$20	$39	$40	$41	$41	$41	$41

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($46)	$1	$4	$1	($19)	($21)	($23)	$9	$10	$11	$10	$11	$12	$12	$3	$3	$1	($30)	($41)	($42)	($51)
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)
Change in DSM	($14)	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($6)
Change in System Fixed Cost	($200)	($0)	($0)	$0	($0)	($0)	$0	($44)	($45)	($46)	($47)	($48)	($49)	($44)	($35)	($35)	($33)	($3)	$5	$5	$11
Net (Benefit)/Cost	($260)	$58	$63	$37	($57)	($78)	($79)	($95)	($94)	($97)	($97)	($101)	($99)	($66)	$24	$44	$46	$44	$43	$42	$40

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($230)	$1	$4	$1	($19)	($20)	($22)	($21)	($23)	($25)	($26)	($27)	($30)	($33)	($34)	($43)	($31)	($16)	($58)	($64)	($63)
Change in Emissions	($8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($2)	($3)	($1)	($2)	($1)	($5)	($2)	($2)
Change in DSM	($3)	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	($34)	($0)	($0)	$0	($0)	($1)	($1)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($12)	($27)	($11)	$13	$8
Net (Benefit)/Cost	($273)	$58	$63	$37	($57)	($78)	($79)	($85)	($85)	($91)	($90)	($96)	($98)	($74)	$15	$28	$34	$36	$9	$31	$30

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($134)	$1	$2	$1	($10)	($12)	($13)	($13)	($14)	($14)	($15)	($15)	($21)	($22)	($23)	($23)	($24)	($24)	($25)	($26)	($26)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($5)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in Deficiency	($2)	$0	$0	($0)	($0)	$0	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($0)	($1)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	$0	($0)	$0	$0	$0
Net (Benefit)/Cost	($141)	$58	$61	$36	($49)	($70)	($69)	($73)	($72)	($76)	($75)	($78)	($82)	($55)	$35	$54	$55	$56	$57	$58	$59

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($122)	$1	$2	$1	($10)	($12)	($13)	($14)	($14)	($15)	($15)	($16)	($21)	($22)	($23)	($23)	($24)	($24)	($24)	($4)	$4
Change in Emissions	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($2)	($2)	$1	$2
Change in VOM	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	$0	$1
Change in DSM	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	($3)
Change in Deficiency	($1)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	($0)	$0	$0	($0)	($0)	($1)	($0)	($1)	($1)	$3	($0)	($4)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($12)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($15)	($28)
Net (Benefit)/Cost	($139)	$58	$61	$37	($49)	($69)	($69)	($73)	($72)	($75)	($74)	($78)	($82)	($55)	$34	$53	$53	$54	$59	$66	$59

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($145)	$1	$2	$1	($10)	($12)	($12)	($13)	($14)	($14)	($15)	($16)	($23)	($25)	($27)	($27)	($27)	($27)	($28)	($29)	($30)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($4)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
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	($9)	$0	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)
Change in Deficiency	($0)	$0	$0	($0)	($0)	($0)	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($2)	($1)	($1)	$5	$0	($1)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$7	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	$3	$3	$3	$3	$2	$2	$2	$4
Net (Benefit)/Cost	($165)	$58	$61	$37	($49)	($69)	($69)	($73)	($72)	($76)	($77)	($83)	($88)	($61)	$27	$45	$48	$49	$55	$51	$52

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($174)	$1	$2	$1	($11)	($13)	($14)	($14)	($16)	($17)	($17)	($18)	($25)	($27)	($27)	($29)	($37)	($38)	($40)	($43)	($50)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
Change in DSM	($13)	$0	$0	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Change in Deficiency	($2)	($0)	$0	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	($0)	($0)	($1)	($2)	($0)	($3)	$0	($1)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$20	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$13	$10	$11	$11	$20
Net (Benefit)/Cost	($171)	$58	$62	$36	($50)	($71)	($71)	($75)	($74)	($79)	($78)	($82)	($87)	($62)	$29	$47	$51	$51	$48	$51	$54

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($159)	$1	$2	$1	($11)	($14)	($14)	($15)	($16)	($18)	($18)	($18)	($26)	($28)	($31)	($33)	($43)	($33)	($22)	($15)	($15)
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($0)	$0	$0
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($6)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in Deficiency	$1	($0)	$0	$0	($0)	$0	$0	($0)	$0	($0)	$0	$0	($0)	($0)	($1)	($1)	($2)	$3	$2	($0)	$1
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($14)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$1	$1	$1	$16	($2)	($16)	($28)	($28)
Net (Benefit)/Cost	($180)	$58	$62	$37	($49)	($71)	($70)	($74)	($74)	($79)	($77)	($82)	($88)	($62)	$25	$43	$48	$48	$46	$41	$44

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($186)	$1	$2	$1	($11)	($13)	($14)	($15)	($16)	($18)	($18)	($19)	($27)	($39)	($45)	($47)	($49)	($32)	($33)	($28)	($27)
Change in Emissions	($16)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($6)	($6)	($5)	($6)	($4)	($4)	($3)	($3)
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	($8)	$0	$0	($1)	($1)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Change in Deficiency	($2)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($0)	($1)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$19	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$18	$19	$20	$22	($4)	($3)	($15)	($18)
Net (Benefit)/Cost	($193)	$58	$61	$36	($50)	($71)	($70)	($74)	($74)	($79)	($79)	($85)	($92)	($61)	$25	$44	$44	$40	$40	$37	$37

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($116)	$1	$3	$1	($14)	($16)	($18)	($4)	($5)	($5)	($5)	($6)	($12)	($13)	($17)	($16)	($17)	($38)	($36)	($39)	($36)
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	($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	$0	$0	$0	$0	$0	$1	$1	$1	$1	$1	$1
Change in Deficiency	($2)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	($0)	($0)	$0	$0	$0	$0	$0	($2)	($3)	($1)	($2)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($119)	($0)	($0)	$0	($0)	($0)	$0	($23)	($24)	($24)	($25)	($25)	($26)	($25)	($23)	($25)	($24)	($1)	($3)	($3)	($8)
Net (Benefit)/Cost	($234)	$58	$62	$37	($53)	($73)	($73)	($86)	($85)	($89)	($89)	($92)	($98)	($70)	$20	$39	$40	$41	$42	$43	$42

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($33)	$1	$3	$1	($14)	($16)	($18)	$11	$12	$12	$12	$12	$8	$8	$1	$0	($1)	($28)	($36)	($38)	($44)
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	($1)	($1)	($1)	($2)
Change in VOM	$1	$0	$0	$0	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)
Change in DSM	($15)	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($3)	($3)	($3)	($4)	($4)	($6)	($6)
Change in Deficiency	($1)	$0	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	$0	$1	$1	$0	($2)	($2)	($1)	($1)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($200)	($0)	($0)	$0	($0)	($0)	$0	($44)	($45)	($46)	($47)	($48)	($49)	($44)	($35)	($35)	($33)	($3)	$5	$5	$11
Net (Benefit)/Cost	($248)	$58	$62	$37	($53)	($73)	($73)	($93)	($92)	($95)	($95)	($100)	($103)	($70)	$23	$43	$44	$44	$44	$45	$46

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	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($191)	$1	$3	$1	($14)	($16)	($17)	($16)	($17)	($18)	($19)	($19)	($28)	($30)	($32)	($43)	($29)	($22)	($49)	($52)	($51)
Change in Emissions	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($3)	($3)	($1)	($2)	($2)	($6)	($4)	($4)
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($0)	($0)	($1)	($0)	($0)
Change in DSM	($3)	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
Change in Deficiency	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($3)	$9	($2)	($3)
Change in PTC losses (dumped energ	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($34)	($0)	($0)	$0	($0)	($1)	($1)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($12)	($27)	($11)	$13	$8
Net (Benefit)/Cost	($240)	$58	$62	$37	($53)	($74)	($73)	($80)	($79)	($83)	($84)	($89)	($96)	($71)	$16	$27	$35	$27	$24	$38	$36

Docket No. UE 352
Exhibit PAC/304
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results

December 2018

Estimated Annual Revenue Requirement Results ($ million)

9 **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	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($394)	$1	$2	$1	($10)	($12)	($13)	($13)	($14)	($14)	($15)	($15)	($21)	($22)	($23)	($23)	($24)	($24)	($25)	($26)	($26)	($46)	($64)	($116)	($121)	($135)	($138)	($141)	($144)	($147)	($150)	($154)	($144)	($97)	($15)
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	($24)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($1)	($2)	($3)	($4)	($7)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($9)	($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	($418)	$1	$2	$1	($11)	($13)	($13)	($14)	($15)	($15)	($16)	($16)	($22)	($22)	($24)	($25)	($26)	($26)	($27)	($27)	($28)	($49)	($68)	($123)	($128)	($143)	($146)	($149)	($153)	($156)	($159)	($163)	($152)	($103)	($16)
2050 Net (Benefit)/Cost	($127)	$0	$1	$3	$16	($1)	($15)	($29)	($37)	($47)	($52)	($61)	($70)	($53)	$27	$41	$37	$33	$28	$21	$18	$10	$18	($6)	($8)	($17)	($19)	($22)	($24)	($25)	($26)	($23)	($7)	($17)	($12)

7 **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	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($334)	$1	$2	$1	($10)	($12)	($13)	($14)	($14)	($15)	($15)	($16)	($21)	($22)	($23)	($23)	($24)	($24)	($24)	($4)	$4	($38)	($52)	($94)	($98)	($110)	($112)	($114)	($117)	($120)	($122)	($125)	($117)	($79)	($13)
Emissions	($9)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($2)	($2)	$1	$2	($1)	($2)	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($3)	($0)
Other Variable Costs	($15)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($2)	($1)	$3	($3)	($6)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($7)	($6)	($4)	($1)
System Fixed Costs	($55)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($15)	($28)	($8)	($11)	($19)	($20)	($22)	($23)	($23)	($24)	($24)	($25)	($25)	($24)	($16)	($3)
Net System Impacts	($413)	$1	$2	$1	($10)	($12)	($13)	($14)	($14)	($15)	($15)	($16)	($21)	($22)	($25)	($26)	($27)	($28)	($25)	($20)	($29)	($49)	($67)	($122)	($127)	($141)	($145)	($148)	($151)	($154)	($158)	($161)	($151)	($102)	($16)
2050 Net (Benefit)/Cost	($121)	$0	$1	$3	$16	($1)	($15)	($28)	($36)	($47)	($52)	($61)	($70)	($53)	$27	$40	$35	$30	$30	$29	$18	$10	$19	($4)	($7)	($15)	($18)	($20)	($22)	($24)	($25)	($21)	($5)	($16)	($11)

8 **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	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($443)	$1	$2	$1	($10)	($12)	($12)	($13)	($14)	($14)	($15)	($16)	($23)	($25)	($27)	($27)	($27)	($27)	($28)	($29)	($30)	($53)	($74)	($133)	($138)	($154)	($158)	($161)	($165)	($168)	($172)	($176)	($164)	($111)	($18)
Emissions	($73)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($4)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($10)	($14)	($24)	($25)	($28)	($29)	($30)	($30)	($31)	($32)	($32)	($30)	($20)	($3)
Other Variable Costs	($31)	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($3)	($2)	($3)	$2	($2)	($4)	($4)	($5)	($9)	($10)	($11)	($11)	($11)	($11)	($12)	($12)	($12)	($11)	($8)	($1)
System Fixed Costs	$33	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	$3	$3	$3	$3	$2	$2	$2	$4	$5	$6	$11	$12	$13	$14	$14	$14	$14	$15	$15	$14	$10	$2
Net System Impacts	($514)	$1	$2	$1	($10)	($12)	($14)	($15)	($15)	($16)	($18)	($21)	($27)	($28)	($31)	($33)	($32)	($33)	($29)	($34)	($36)	($62)	($86)	($155)	($161)	($180)	($184)	($188)	($192)	($197)	($201)	($206)	($192)	($130)	($21)
2050 Net (Benefit)/Cost	($223)	$0	$1	$3	$16	($1)	($15)	($29)	($37)	($48)	($55)	($66)	($76)	($59)	$20	$32	$30	$25	$26	$14	$11	($3)	$0	($38)	($42)	($54)	($58)	($61)	($64)	($66)	($68)	($66)	($46)	($44)	($16)

3 **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	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($552)	$1	$2	$1	($11)	($13)	($14)	($14)	($16)	($17)	($17)	($18)	($25)	($27)	($27)	($29)	($37)	($38)	($40)	($43)	($50)	($67)	($93)	($168)	($175)	($195)	($200)	($204)	($209)	($213)	($218)	($223)	($208)	($140)	($22)
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	($55)	$0	$0	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($4)	($5)	($3)	($6)	($3)	($4)	($7)	($9)	($17)	($17)	($19)	($20)	($20)	($21)	($21)	($22)	($22)	($21)	($14)	($2)
System Fixed Costs	$91	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$13	$10	$11	$11	$20	$13	$18	$32	$33	$37	$38	$38	$39	$40	$41	$42	$39	$26	$4
Net System Impacts	($516)	$1	$2	$1	($11)	($14)	($15)	($16)	($17)	($19)	($19)	($20)	($27)	($29)	($30)	($32)	($29)	($30)	($35)	($35)	($34)	($61)	($85)	($153)	($159)	($178)	($182)	($186)	($190)	($194)	($198)	($203)	($189)	($128)	($20)
2050 Net (Benefit)/Cost	($224)	$0	$1	$3	$15	($3)	($17)	($31)	($39)	($51)	($56)	($65)	($76)	($60)	$22	$34	$34	$28	$19	$13	$12	($2)	$2	($36)	($40)	($52)	($55)	($58)	($61)	($63)	($65)	($63)	($44)	($42)	($16)

1 **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	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($470)	$1	$2	$1	($11)	($14)	($14)	($15)	($16)	($18)	($18)	($18)	($26)	($28)	($31)	($33)	($43)	($33)	($22)	($15)	($15)	($55)	($77)	($139)	($144)	($161)	($165)	($168)	($172)	($176)	($180)	($184)	($171)	($116)	($18)
Emissions	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($0)	$0	$0	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($0)
Other Variable Costs	($24)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)	($2)	($2)	($2)	($2)	($4)	$2	($0)	($2)	($0)	($3)	($4)	($8)	($8)	($9)	($9)	($9)	($9)	($10)	($10)	($10)	($9)	($6)	($1)
System Fixed Costs	($65)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$1	$1	$1	$16	($2)	($16)	($28)	($28)	($9)	($12)	($23)	($23)	($26)	($27)	($27)	($28)	($29)	($29)	($30)	($28)	($19)	($3)
Net System Impacts	($565)	$1	$2	$1	($11)	($14)	($15)	($15)	($17)	($19)	($19)	($20)	($27)	($29)	($33)	($36)	($32)	($34)	($38)	($44)	($44)	($68)	($95)	($171)	($178)	($198)	($203)	($207)	($212)	($217)	($221)	($226)	($211)	($143)	($23)
2050 Net (Benefit)/Cost	($273)	$0	$1	$4	$16	($2)	($16)	($30)	($39)	($51)	($55)	($65)	($76)	($60)	$18	$30	$30	$25	$17	$4	$2	($9)	($8)	($53)	($58)	($72)	($76)	($80)	($83)	($86)	($88)	($86)	($66)	($57)	($18)

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
Project Net Costs															
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52
System Impacts															
NPC	($596)	$1	$2	$1	($11)	($13)	($14)	($15)	($16)	($18)	($18)	($19)	($27)	($39)	($45)
Emissions	($64)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($6)	($6)
Other Variable Costs	($37)	$0	$0	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)
System Fixed Costs	$85	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$18	$19
Net System Impacts	($612)	$1	$2	$1	($11)	($14)	($15)	($16)	($17)	($19)	($21)	($23)	($32)	($29)	($33)
2050 Net (Benefit)/Cost	($321)	$0	$1	$3	$15	($3)	($17)	($30)	($39)	($51)	($57)	($68)	($81)	($59)	$18

(Benefit)/Cost	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	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																				
NPC	($47)	($49)	($32)	($33)	($28)	($27)	($73)	($101)	($183)	($190)	($212)	($217)	($222)	($227)	($232)	($237)	($242)	($226)	($153)	($24)
Emissions	($5)	($6)	($4)	($4)	($3)	($3)	($9)	($12)	($22)	($22)	($25)	($26)	($26)	($27)	($27)	($28)	($29)	($27)	($18)	($3)
Other Variable Costs	($2)	($2)	($3)	($3)	($2)	($3)	($5)	($6)	($12)	($12)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($14)	($10)	($2)
System Fixed Costs	$20	$22	($4)	($3)	($15)	($18)	$12	$16	$29	$31	$34	$35	$36	$37	$37	$38	$39	$36	$25	$4
Net System Impacts	($34)	($36)	($42)	($43)	($48)	($51)	($74)	($103)	($186)	($194)	($216)	($221)	($226)	($231)	($236)	($241)	($247)	($231)	($156)	($25)
2050 Net (Benefit)/Cost	$31	$27	$17	$11	$0	($5)	($16)	($17)	($69)	($74)	($90)	($95)	($99)	($102)	($105)	($108)	($107)	($85)	($70)	($20)

Estimated Annual Revenue Requirement Results ($ million)

6 **High Natural Gas, Zero CO2 Price-Policy Scenario**

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($374)	$1	$3	$1	($14)	($16)	($18)	($4)	($5)	($5)	($5)	($6)	($12)	($13)	($17)	($16)	($17)	($38)	($36)	($39)	($36)	($46)	($64)	($115)	($120)	($133)	($136)	($139)	($142)	($146)	($149)	($152)	($142)	($96)	($15)
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	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	$0	$0	$0	$1	$1	$1	$1	$1	$1	($2)	($3)	($1)	($1)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($0)
System Fixed Costs	($306)	($0)	($0)	$0	($0)	($0)	$0	($23)	($24)	($24)	($25)	($25)	($26)	($25)	($23)	($25)	($24)	($1)	($3)	($3)	($8)	($33)	($46)	($83)	($87)	($97)	($99)	($101)	($103)	($106)	($108)	($110)	($103)	($70)	($11)
Net System Impacts	($681)	$1	$3	$1	($14)	($17)	($18)	($27)	($28)	($29)	($30)	($30)	($37)	($37)	($38)	($40)	($40)	($41)	($42)	($43)	($46)	($79)	($110)	($199)	($207)	($231)	($236)	($241)	($246)	($252)	($257)	($263)	($246)	($166)	($26)
2050 Net (Benefit)/Cost	($389)	$0	$1	$4	$12	($5)	($19)	($42)	($50)	($61)	($66)	($76)	($86)	($68)	$13	$26	$22	$18	$13	$6	$1	($21)	($24)	($81)	($87)	($105)	($109)	($114)	($118)	($121)	($124)	($123)	($100)	($80)	($22)

4 **High Natural Gas, Medium CO2 Price-Policy Scenario**

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($157)	$1	$3	$1	($14)	($16)	($18)	$11	$12	$12	$12	$12	$8	$8	$1	$0	($1)	($28)	($36)	($38)	($44)	($22)	($31)	($55)	($58)	($64)	($66)	($67)	($69)	($70)	($72)	($73)	($69)	($46)	($7)
Emissions	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	($1)	($1)	($1)	($2)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)
Other Variable Costs	($56)	$0	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($1)	($1)	($3)	($6)	($7)	($8)	($7)	($7)	($10)	($18)	($19)	($21)	($22)	($22)	($23)	($23)	($24)	($24)	($23)	($15)	($2)
System Fixed Costs	($461)	($0)	($0)	$0	($0)	($0)	$0	($44)	($45)	($46)	($47)	($48)	($49)	($44)	($35)	($35)	($33)	($3)	$5	$5	$11	($46)	($64)	($116)	($121)	($135)	($138)	($141)	($144)	($148)	($151)	($154)	($144)	($97)	($16)
Net System Impacts	($677)	$1	$3	$1	($14)	($17)	($18)	($34)	($34)	($35)	($36)	($38)	($42)	($37)	($36)	($36)	($36)	($38)	($39)	($41)	($42)	($76)	($106)	($191)	($199)	($222)	($227)	($232)	($237)	($242)	($248)	($253)	($237)	($160)	($25)
2050 Net (Benefit)/Cost	($386)	$0	$1	$4	$12	($5)	($19)	($49)	($56)	($67)	($73)	($83)	($91)	($68)	$16	$30	$26	$21	$15	$7	$4	($18)	($20)	($74)	($79)	($96)	($100)	($105)	($109)	($112)	($115)	($113)	($91)	($74)	($21)

5 **High Natural Gas, High CO2 Price-Policy Scenario**

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($594)	$1	$3	$1	($14)	($16)	($17)	($16)	($17)	($18)	($19)	($19)	($28)	($30)	($32)	($43)	($29)	($22)	($49)	($52)	($51)	($72)	($99)	($180)	($187)	($209)	($213)	($218)	($223)	($228)	($233)	($238)	($222)	($150)	($24)
Emissions	($43)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($3)	($3)	($1)	($2)	($2)	($6)	($4)	($4)	($6)	($8)	($14)	($15)	($17)	($17)	($17)	($18)	($18)	($19)	($19)	($18)	($12)	($2)
Other Variable Costs	($16)	$0	$0	$0	($0)	($0)	($0)	($1)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($4)	$7	($4)	($5)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($7)	($7)	($6)	($4)	($1)
System Fixed Costs	($105)	($0)	($0)	$0	($0)	($1)	($1)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($12)	($27)	($11)	$13	$8	($13)	($17)	($31)	($33)	($36)	($37)	($38)	($39)	($40)	($41)	($42)	($39)	($26)	($4)
Net System Impacts	($758)	$1	$3	$1	($14)	($17)	($18)	($21)	($22)	($23)	($25)	($27)	($36)	($39)	($42)	($51)	($45)	($55)	($59)	($47)	($52)	($92)	($128)	($230)	($240)	($268)	($274)	($280)	($286)	($292)	($299)	($305)	($285)	($192)	($31)
2050 Net (Benefit)/Cost	($466)	$0	$1	$4	$12	($6)	($20)	($36)	($44)	($55)	($61)	($72)	($84)	($70)	$9	$14	$17	$4	($5)	$1	($5)	($33)	($41)	($113)	($120)	($142)	($147)	($152)	($157)	($161)	($166)	($165)	($139)	($107)	($26)

Docket No. UE 352
Exhibit PAC/400
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Steven R. McDougal

December 2018

DIRECT TESTIMONY OF STEVEN R. MCDOUGAL

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/401—Annual RAC Repowering Revenue Requirement

Exhibit PAC/402—Monthly RAC Repowering Revenue Requirement – October 2019

Exhibit PAC/403—Monthly RAC Repowering Revenue Requirement – December 2019

Exhibit PAC/404—Capital Structure, Property Tax, Revenue Requirement Gross-up

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

A. My name is Steven R. McDougal, and my business address is 1407 W. North Temple, Suite 330, Salt Lake City, Utah 84116. My present position is Director of Revenue Requirements.

QUALIFICATIONS

Q. Please describe your education and professional background.

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services and a Bachelor of Science degree in Accounting from Brigham Young University. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars. I have been employed with PacifiCorp and its predecessor, Utah Power and Light Company, since 1983. My experience includes various positions with regulation, finance, resource planning, and internal audit.

Q. What are your current responsibilities with PacifiCorp?

A. My primary responsibilities include overseeing the calculation and reporting of the company's regulated earnings and revenue requirement, assuring that the interjurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the company operates.

PURPOSE OF TESTIMONY

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

A. I present and explain the calculation of the repowered wind projects' non-transition adjustment mechanism related revenue requirement to be included in the Renewable Adjustment Clause (RAC). Specifically, my testimony:

- Describes the proposed ratemaking for the repowered wind projects;
- Calculates the Oregon allocated incremental operating expenses and capital revenue requirement cost associated with wind repowering;
- Specifies the amounts that the company requests to recover through the RAC attributable to the revenue requirement changes associated with each of the company's proposed RAC rate change effective dates; and
- Explains the proposed accounting treatment of the replaced wind plant investment.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. In this RAC filing, PacifiCorp seeks recovery of the non-transition adjustment mechanism Oregon-allocated revenue requirement associated with repowering the company's existing fleet of wind resources. PacifiCorp proposes to implement the RAC in two stages: October 1, 2019, and December 1, 2019, to recover costs in a manner that will coincide with the customer benefits from net power cost and production tax credits included in the 2019 transition adjustment mechanism (TAM). The requested RAC recovery amounts are $16.0 million, through rates effective October 1, 2019, and an additional $20.8 million, through rates effective December 1, 2019.

PROPOSED RATEMAKING

Q. Please explain PacifiCorp's proposed ratemaking for inclusion of the repowered wind projects in rates.

A. PacifiCorp seeks recovery of the revenue requirement associated with the costs of the repowered wind projects that are scheduled to be completed in 2019 through this RAC filing. Cost benefits associated with repowering have been approved as part of

PacifiCorp's 2019 TAM.[1] PacifiCorp proposes two rate effective dates of October 1, 2019 and December 1, 2019, for implementing the proposed rate changes. These proposed dates will allow for the natural grouping of the revenue requirement changes for the repowered wind projects that have achieved final completion as of the respective rate effective dates, minimizing potential regulatory lag and maximizing the matching of costs and benefits.

Q. Please identify the wind repowering projects included in each of the proposed RAC rate effective dates of October 1, 2019 and December 1, 2019.

A. The October 1, 2019 rate effective date will include the repowering projects for Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I. The December 1, 2019 rate effective date will include the repowering projects for Goodnoe Hills, High Plains, McFadden Ridge, Marengo I and Marengo II.

Q. Do these two rate effective dates include all future repowering projects that PacifiCorp anticipates seeking rate recovery for?

A. No. Glenrock III and Dunlap repowering projects will not be completed until 2020. As such, these projects did not have net power cost benefits, including PTC benefits, reflected in the 2019 TAM. PacifiCorp will seek additional RAC rate recovery for those projects at a later time.

[1] See *In the Matter of PacifiCorp dba Pacific Power 2019 Transition Adjustment Mechanism,* Docket No. UE 339, Order No. 18-421 (Oct. 26, 2018).

Q. Does PacifiCorp have any wind repowering projects that it will not seek recovery of through the RAC?

A. Yes. The Rolling Hills wind resource is not currently included in Oregon rates; therefore, PacifiCorp will not seek recovery of the Rolling Hills repowering project in the RAC.

Q. If wind projects are repowered before the rate effective dates of October 1, 2019 and December 1, 2019, is PacifiCorp proposing to defer the costs associated with these early completions and amortize those changes at a future time?

A. No. PacifiCorp is proposing that only the costs of completed repowering projects as of the rate effective dates be considered in the RAC rate adjustments.

REVENUE REQUIREMENT

Q. Have you prepared exhibits that show the calculation of the proposed RAC rate adjustments for each of the rate effective dates, October 1, 2019, and December 1, 2019?

A. Yes. Please refer to Exhibit PAC/401, which shows the annual revenue requirement of the incremental capital and operating costs associated with the repowering of Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I for the one-year period October 1, 2019 through September 30, 2020. These projects are scheduled to achieve final turbine commissioning before October 1, 2019. As calculated in Exhibit PAC/401, PacifiCorp is seeking an annual recovery of $16.0 million through the RAC with a proposed effective date of October 1, 2019.

Exhibit PAC/401 also shows the annual revenue requirement of the incremental capital and operating costs associated with the repowering of Goodnoe

Hills, High Plains, McFadden Ridge, Marengo I and Marengo II for the one-year period December 1, 2019 through November 30, 2020. These projects are scheduled to achieve final turbine commissioning before December 1, 2019. As calculated in Exhibit PAC/401, PacifiCorp is seeking an annual recovery of $20.8 million through the RAC with a proposed effective date of December 1, 2019.

Q. How are the revenue requirement costs allocated to Oregon?

A. All costs excluding property tax are allocated using the 2019 forecast System Generation factor used in the 2019 TAM filing. Property tax is allocated using the Gross Plant System factor from PacifiCorp's December 2017 Results of Operations filing, consistent with the calculation of the average Oregon property tax rate also from the December 2017 Results of Operations filing, addressed later in my testimony.

Q. Please describe the revenue requirement components included in Exhibit PAC/401.

A. The plant revenue requirement consists of the incremental pre-tax rate of return on average net rate base, operation and maintenance expense, depreciation, property taxes, and wind tax. Net power cost and production tax credits are excluded from the RAC and were instead included in the 2019 TAM filing. Through the combination of the TAM and the RAC, the benefits and costs of repowering will be incorporated into customer rates.

Net rate base is calculated using a 13-month average of gross plant less accumulated depreciation and accumulated deferred income tax balances. The 13-month average balances are derived from the period October 1, 2019 through

October 1, 2020, and December 1, 2019 through December 1, 2020, for the rate effective dates of October 1, 2019 and December 1, 2019, respectively. Exhibits PAC/402 and PAC/403 provide the monthly detail used to derive the 13-month averages.

Q. Please describe the capital structure and pre-tax cost of capital proposed in the RAC.

A. Please refer to Exhibit PAC/404. The capital structure and capital costs are taken from the company's December 2017 Results of Operations filing, reflecting the currently authorized capital structure and capital costs approved as part of PacifiCorp's last Oregon general rate case.[2] The cost of capital is grossed up to a pre-tax rate of return using the consolidated tax rate consistent with current tax law.

Q. Does the operation and maintenance expense (O&M) shown in Exhibit PAC/401 represent the incremental O&M associated with repowering the various wind resources?

A. Yes. The O&M is incremental to repowering and is explained in the testimony of Mr. Timothy Hemstreet, Exhibit PAC/200.

Q. Please explain the depreciation expense in Exhibit PAC/401.

A. The depreciation expense shown in Exhibit PAC/401 is the increased depreciation expense associated with the incremental capital investment placed in service due to repowering.

[2] *See In the Matter of PacifiCorp dba Pacific Power Request for a General Rate Revision*, Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).

Q. Does this incremental depreciation expense include the impact of the change in depreciation expense associated with the equipment replaced during the repowering construction activities?

A. No. The asset value of the replaced wind plant is addressed in the 2018 Depreciation Study filed in docket UM 1968.[3] The depreciation expense included in the RAC has been calculated using currently approved depreciation rates.

Q. Please describe the property tax calculation included in the proposed RAC.

A. Please refer to Exhibit PAC/404, which shows the calculation of the average Oregon property tax rate from PacifiCorp's December 2017 Results of Operations filing. The average property tax rate is calculated by dividing the Oregon allocated property taxes by the Oregon allocated net electric plant in service (EPIS). The property taxes attributable to repowering are calculated by multiplying this average property tax rate by the preceding year's December ending net EPIS of the repowering project.

Q. Please describe the Wyoming Wind Tax included in the proposed RAC.

A. The current Wyoming State tax collection of $1/MWh wind tax has been applied to the incremental change in Wyoming wind generation as a result of repowering. The amount of incremental wind generation due to repowering is addressed in the testimony of Mr. Hemstreet, Exhibit PAC/200.

Q. Are there any other cost considerations that should be addressed as part of the wind repowering RAC?

A. Yes. The RAC revenue requirement adjustment includes a gross-up for the incremental rate burden associated with incremental franchise taxes, bad debt

[3] *See In the Matter of PacifiCorp dba Pacific Power Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968, (Sep. 13, 2018).

expense, resource suppliers tax, and public utility commission fees. These costs have been included in Exhibit PAC/401.

REQUEST FOR RECOVERY OF REPOWERING COSTS

Q. What is the amount of rate adjustment that PacifiCorp is requesting through the RAC?

A. PacifiCorp is requesting an annualized amount of $16.0 million through the RAC rates proposed to be effective October 1, 2019, to recover the repowering capital and operating revenue requirement concurrent with the rate reductions provided through the TAM for the repowering net power cost and production tax credit benefits.

Additionally, PacifiCorp is requesting an annualized amount of $20.8 million, in addition to the October 1, 2019 adjustment, through the RAC rates proposed to be effective December 1, 2019, to recover the second tranche of revenue requirement associated with the next block of repowered wind turbines. PacifiCorp will update these costs consistent with the requirements of Order No. 07-572.[4]

Q. Does this conclude your direct testimony?

A. Yes.

[4] *In the Matter of Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 4 (Dec. 19, 2007).

Docket No. UE 352
Exhibit PAC/401
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Annual RAC Repowering Revenue Requirement

December 2018

PacifiCorp
Oregon
Renewable Adjustment Clause
Revenue Requirement

Line No.	$-Thousands	Reference	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			RAC Effective Date October 1, 2019				RAC Effective Date December 1, 2019			
			Oct. 2019 - Sept. 2020				Dec. 2019 - Nov. 2020			
			Total Company	Factor	Factor %	Oregon Allocated	Total Company	Factor	Factor %	Oregon Allocated
	Plant Revenue Requirement									
1	Capital Investment	Footnote 1	358,157	SG	26.7248%	95,717	469,155	SG	26.7248%	125,381
2	Depreciation Reserve	Footnote 1	(7,503)	SG	26.7248%	(2,005)	(9,702)	SG	26.7248%	(2,593)
3	Accumulated DIT Balance	Footnote 1	(22,293)	SG	26.7248%	(5,958)	(34,474)	SG	26.7248%	(9,213)
4	Net Rate Base	sum of lines 1-3	328,361			87,754	424,979			113,575
5	Pre-Tax Rate of Return	line 20	11.426%			11.426%	11.426%			11.426%
6	Pre-Tax Return on Rate Base	line 4 * line 5	37,519			10,027	48,559			12,977
7	Operation & Maintenance	Footnote 2	4,994	SG	26.7248%	1,335	6,481	SG	26.7248%	1,732
8	Depreciation	Footnote 3 and 4	12,342	SG	26.7248%	3,298	16,132	SG	26.7248%	4,311
9	Property Taxes	Footnote 2	3,081	GPS	27.1069%	835	4,058	GPS	27.1069%	1,100
10	Wind Tax	Footnote 2	160	SG	26.7248%	43	100	SG	26.7248%	27
11	**Rev. Reqt. Before Revenue Gross-up**	sum of lines 6-11	**58,096**			**15,538**	**75,330**			**20,147**
12	Franchise Taxes	PAC/404, line 17				376				487
13	Bad Debt Expense	PAC/404, line 18				77				99
14	Resource Supplier Tax	PAC/404, line 19				22				28
15	PUC Fee	PAC/404, line 20				48				62
16	**Total Revenue Requirement**	sum of lines 11-15				**16,012**				**20,762**
17	Federal/State Combined Tax Rate	PAC/404, line 5	24.587%							
18	Net to Gross Bump up Factor = (1/(1-tax rate))	PAC/404, line 6	1.3260							
19	Pretax Return	PAC/404, line 4	11.426%							
20	Property Tax Rate	PAC/404, line 14	0.87%							
21	Oregon SG Factor	PAC/404, line 15	26.7248%							
22	Oregon GPS Factor	PAC/404, line 16	27.1069%							

Footnotes:
1) Capital balances equal the 13-month average of the monthly balances in PAC/402 or PAC/403.
2) Equals the annual cost of the first full year subsequent to the rate effective date. See PAC/402 or PAC/403
3) Equals the 12 consecutive months beginning with the rate reffective date. See PAC/402 or PAC/403.
4) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study.

Docket No. UE 352
Exhibit PAC/402
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Monthly RAC Repowering Revenue Requirement – October 2019

December 2018

PacifiCorp
Oregon
Wind Repowering - Monthly RAC RevReqt - Oct 2019
Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I

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		-	-	-	-	-	-	-	-	358,060	358,060	358,060	358,060
2	Depreciation Reserve		-	-	-	-	-	-	-	-	(1,333)	(2,361)	(3,390)	(4,418)
3	Accumulated DIT Balance		-	-	-	-	-	-	-	-	(13,203)	(13,203)	(13,203)	(17,604)
4	Net Rate Base	sum of lines 1-3	-	-	-	-	-	-	-	-	343,524	342,496	341,467	336,038
5	Operation & Maintenance		-	-	-	-	-	-	-	-	-	416	416	416
6	Depreciation	Footnote 1	-	-	-	-	-	-	-	-	-	1,028	1,028	1,028
7	Property Taxes	Prior December (line 1 + line 2) x line 9	-	-	-	-	-	-	-	-	-	-	-	-
8	Wind Tax		-	-	-	-	-	-	-	-	-	13	13	13
9	Property Tax Rate	PAC/404, line 14	0.87%											

Footnotes:
1) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

PacifiCorp
Oregon
Wind Repowering - Monthly RAC RevReqt - Oct 2019
Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I

Line No.	$-Thousands	Reference	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September
	Total Company										
	Plant Revenue Requirement										
1	Capital Investment		358,060	358,060	358,060	358,060	358,060	358,060	358,483	358,483	358,483
2	Depreciation Reserve		(5,446)	(6,474)	(7,502)	(8,530)	(9,559)	(10,587)	(11,616)	(12,646)	(13,675)
3	Accumulated DIT Balance		(17,604)	(17,604)	(23,785)	(23,785)	(23,785)	(29,966)	(29,966)	(29,966)	(36,147)
4	Net Rate Base	sum of lines 1-3	335,010	333,982	326,773	325,745	324,716	317,507	316,901	315,871	308,661
5	Operation & Maintenance		416	416	416	416	416	416	416	416	416
6	Depreciation	Footnote 1	1,028	1,028	1,028	1,028	1,028	1,028	1,029	1,029	1,029
7	Property Taxes	Prior December (line 1 + line 2) x line 9	257	257	257	257	257	257	257	257	257
8	Wind Tax		13	13	13	13	13	13	13	13	13
9	Property Tax Rate	PAC/404, line 14									

Footnotes:
1) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

Docket No. UE 352
Exhibit PAC/403
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Monthly RAC Repowering Revenue Requirement – December 2019

December 2018

PacifiCorp
Oregon
Wind Repowering - Monthly RAC RevReqt - Dec 2019
Goodnoe Hills, High Plains, McFadden Ridge, Marengo I and Marengo II

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		-	-	-	-	-	-	-	-	-	-	468,772	468,772
2	Depreciation Reserve		-	-	-	-	-	-	-	-	-	-	(1,640)	(2,983)
3	Accumulated DIT Balance		-	-	-	-	-	-	-	-	-	-	(17,784)	(23,712)
4	Net Rate Base	sum of lines 1-3	-	-	-	-	-	-	-	-	-	-	449,348	442,077
5	Operation & Maintenance		-	-	-	-	-	-	-	-	-	-	-	540
6	Depreciation	Footnote 1	-	-	-	-	-	-	-	-	-	-	-	1,343
7	Property Taxes	Prior December (line 1 + line 2) x line 9	-	-	-	-	-	-	-	-	-	-	-	-
8	Wind Tax		-	-	-	-	-	-	-	-	-	-	-	8
9	Property Tax Rate	PAC/404, line 14	0.87%											

Footnotes:
1) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

PacifiCorp
Oregon
Wind Repowering - Monthly RAC RevReqt - Dec 2019
Goodnoe Hills, High Plains, McFadden Ridge, Marengo I and Marengo II

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
	Total Company												
	Plant Revenue Requirement												
1	Capital Investment		468,772	468,772	468,772	468,772	468,772	468,772	469,768	469,768	469,768	469,768	469,768
2	Depreciation Reserve		(4,326)	(5,669)	(7,012)	(8,356)	(9,699)	(11,042)	(12,388)	(13,734)	(15,080)	(16,426)	(17,772)
3	Accumulated DIT Balance		(23,712)	(23,712)	(31,814)	(31,814)	(31,814)	(39,915)	(39,915)	(39,915)	(48,017)	(48,017)	(48,017)
4	Net Rate Base	sum of lines 1-3	440,734	439,391	429,946	428,603	427,260	417,815	417,465	416,119	406,671	405,325	403,979
5	Operation & Maintenance		540	540	540	540	540	540	540	540	540	540	540
6	Depreciation	Footnote 1	1,343	1,343	1,343	1,343	1,343	1,343	1,346	1,346	1,346	1,346	1,346
7	Property Taxes	Prior December (line 1 + line 2) x line 9	338	338	338	338	338	338	338	338	338	338	338
8	Wind Tax		8	8	8	8	8	8	8	8	8	8	8
9	Property Tax Rate	PAC/404, line 14											

Footnotes:
1) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

Docket No. UE 352
Exhibit PAC/404
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Capital Structure, Property Tax, Revenue Requirement Gross-up

December 2018

PacifiCorp
Oregon
Wind Repowering - Capital Structure, Property Tax, and Rev Reqt Gross-up

Results of Operations Oregon Period Ended December 2017
Updated with new consolidated tax rate consistent with the new tax law
Effective 12/31/2017

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Tax Gross-up	Pre-Tax Cost
1	Debt	48.490%	5.261%	2.551%		2.551%
2	Preferred	0.020%	6.753%	0.001%	1.326	0.002%
3	Common	51.490%	9.800%	5.046%	1.326	8.873%
4			**TOTAL**	**7.598%**		**11.426%**
5	Consolidated Tax Rate		24.587%			
6	Tax Gross-up factor for PTC = (1/(1 - tax rate))		1.3260			

Property Tax Calculation as filed in Results of Operations Oregon Period Ended December 2017

Line no.		
7	Total Company	145,325,972
8	Oregon GPS Factor [2]	27.1069%
9	Oregon Property Taxes	39,393,317
10	Oregon Gross EPIS	7,343,325,727
11	Oregon Accum. Depr.	(2,661,498,413)
12	Oregon Accum. Amort.	(159,988,390)
13	Oregon Net EPIS	4,521,838,924
14	Estimated Oregon Property Tax Rate	0.871%
15	Forecast 2019 SG Factor [1]	26.7248%
16	Results of Operations Oregon 2017 GPS Factor [2]	27.1069%

Line no.	Franchise Tax and Bad Debt Percentage [3]	Percentage of Revenue	w/ Tax Gross-up
17	Franchise Tax	2.340%	2.419%
18	Bad Debt Percentage	0.477%	0.493%
19	Resource Suppliers Tax	0.134%	0.139%
20	PUC Fee	0.300%	0.310%

Footnotes:

1 SG Factor from 2019 TAM filing
2 Results of Operations, December 2017, Page 9.2
3 Results of Operations, December 2017, Page 4.6.1

Docket No. UE 352
Exhibit PAC/500
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

December 2018

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

TABLE OF CONTENTS

ATTACHED EXHIBITS

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

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the company's six-state service territory.

PURPOSE OF TESTIMONY

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

A. I present the company's proposed Renewable Adjustment Clause (RAC) prices and proposed tariff changes. I also provide a summary of the impact of the proposed rate changes on customers' bills.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. I show that the proposed RAC results in an overall rate increase of $16.0 million or 1.2 percent on October 1, 2019, followed by an incremental increase of $20.8 million or 1.6 percent on December 1, 2019. The rate impact varies by customer class with rate spread based on present generation revenues. The total bill increase for the average residential customer resulting from both RAC rate changes is $2.69 per month.

RATES AND TARIFF

Q. Please describe the company's tariff rate schedule that collects the RAC adjustment from customers.

A. The company's Schedule 202, Renewable Adjustment Clause, describes the RAC and contains the per kilowatt-hour adjustments applied to customers' bills. The current tariff rates were set to zero in 2010 when the amounts previously collected through the rate schedule were incorporated into base rates as part of the company's general rate case, docket UE 210.

Q. What is the total repowering revenue requirement PacifiCorp is seeking recovery for at this time?

A. As described in the testimony of Mr. Steven R. McDougal, the requested RAC recovery amounts are $16.0 million, through rates effective October 1, 2019, and an additional $20.8 million, through rates effective December 1, 2019.

Q. What basis is used for the RAC rate spread?

A. The special conditions in Schedule 202 provide that "Costs recovered through the rate schedule will be allocated across customer classes using the applicable forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kilowatt-hour to each applicable rate schedule."[1]

[1] PacifiCorp rate schedule 202, Renewable Adjustment Clause, Supply Service Adjustment page 2, special condition 3.

The company calculated a generation rate spread based on the applicable forecast energy and generation revenue from the most recent Transition Adjustment Mechanism filing, docket UE 339, for a 2019 test year.

Q. Have you calculated proposed RAC per kilowatt-hour adjustment rates by rate schedule?

A. Yes. Exhibit PAC/501 shows the rate spread and the calculation of the RAC rates for both the October 1, 2019 and December 1, 2019 price changes. The rates to collect the December 1 revenue requirement have been calculated separately and added to the October 1 rates to show the total combined rates for the tariff to be effective December 1.

Q. Have you updated the rate schedule to reflect the change in applicability to direct access customers as described in the testimony of Ms. Etta Lockey?

A. Yes. As described by Ms. Etta P. Lockey, the RAC adjustment should apply to direct access customers since these customers receive the benefit of the production tax credits for these resources through the transition adjustments. Exhibit PAC/502 contains the proposed revisions to Schedule 202, Renewable Adjustment Clause. The applicability section has been revised to reflect this change and the list of applicable rate schedules has been updated to include direct access delivery service schedules.

Q. Does the company propose any other changes to the rate schedule?

A. Yes. The company proposes two other changes to Schedule 202. First, a Special Condition has been added in order to allow for a timeline different than the April 1 filing timeline currently set forth in the special conditions, if approved by the

Commission. This will accommodate the timeline requested in this application without modifying the existing language for future RAC filings.

Second, PacifiCorp proposes a housekeeping edit to remove from the Purpose section outdated language referencing OAR 860-022-0041. This housekeeping edit is appropriate because the OAR was repealed following the enactment of Senate Bill 967 in 2011 in the rulemaking docketed as AR 553.

Q. What rates are reflected in the tariff in Exhibit PAC/502?

A. The proposed tariff in Exhibit PAC/502 includes the proposed rates for October 1.

For rates effective December 1, 2019, the company proposes to file a compliance filing updating Schedule 202 with the total December 1 rates shown in Exhibit PAC/501. The compliance filing would be made on or before November 1, 2019.

COMPARISON OF PRESENT AND PROPOSED RATES

Q. What are the overall rate effects of the changes proposed in this filing?

A. The overall effect of the proposed rates is a rate increase of 1.2 percent, on a net basis, effective October 1, 2019, followed by an incremental increase of 1.6 percent, on a net basis, effective December 1, 2019. The rate change varies by customer type. Exhibit PAC/503 shows the effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. Page 1 of the exhibit shows the proposed October 1 rate change. Page 2 of the exhibit shows the proposed incremental December 1 rate change. On both tables, the net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific

Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Did you prepare exhibits showing the impact on customer bills as a result of the proposed rate changes?

A. Yes. Exhibit PAC/504 contains monthly billing comparisons for the October 1 rate change for customers at different usage levels served on each of the major delivery service schedules. Exhibit PAC/505 contains monthly billing comparisons showing the incremental rate impact of the December 1 rate change. Each comparison shows the customer bill before and after the proposed change and shows the change as a percentage. These bill comparisons include the effects of all adjustments schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is $1.18 beginning October 1 plus an additional $1.51 beginning December 1. The total monthly bill increase for this customer from present rates is $2.69.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 352
Exhibit PAC/501
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Renewable Adjustment Clause, Rate Spread and Rate Calculation

December 2018

PACIFIC POWER
STATE OF OREGON
RENWABLE ADJUSTMENT CLAUSE - RATE SPREAD AND RATE CALCULATION
FORECAST 12 MONTHS ENDING DECEMBER 31, 2019

Line No.	Description	Sch No.	No. of Cust	MWh	Present Generation Rate Spread*	Proposed Schedule 202 October 1 Rates Rates ¢/kWh	October 1 Rates Revenues $	December 1 Adder Rates ¢/kWh	December 1 Adder Revenues $	Total Dec 1 Rates ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
							(4)*(6)		(4)*(8)	(6)+(8)
	Residential									
1	Residential	4	506,345	5,401,764	42.6654%	0.126	$6,806,223	0.163	$8,804,875	0.289
2	**Total Residential**		506,345	5,401,764			$6,806,223		$8,804,875	
	Commercial & Industrial									
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	8.6008%	0.121	$1,378,460	0.157	$1,788,580	0.278
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	15.2694%	0.124	$2,445,325	0.161	$3,174,978	0.285
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	9.8180%	0.118	$1,567,714	0.153	$2,032,714	0.271
6	Large General Service >= 1,000 kW	48	195	3,221,037	21.6635%	0.107	$3,446,510	0.139	$4,477,241	0.246
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859		0.107	$53,349	0.139	$69,304	0.246
8	Agricultural Pumping Service	41	7,982	222,624	1.7016%	0.122	$271,601	0.159	$353,972	0.281
9	**Total Commercial & Industrial**		100,164	7,933,350			$9,162,958		$11,896,789	
	Lighting									
10	Outdoor Area Lighting Service	15	6,305	9,058	0.0544%	0.096	$8,696	0.124	$11,232	0.220
11	Street Lighting Service	50	225	7,713	0.0382%	0.079	$6,093	0.103	$7,944	0.182
12	Street Lighting Service HPS	51	815	19,940	0.1557%	0.125	$24,925	0.162	$32,303	0.287
13	Street Lighting Service	52	35	404	0.0024%	0.096	$388	0.124	$501	0.220
14	Street Lighting Service	53	273	9,678	0.0247%	0.041	$3,968	0.053	$5,129	0.094
15	Recreational Field Lighting	54	104	1,345	0.0059%	0.070	$942	0.091	$1,224	0.161
16	**Total Public Street Lighting**		7,757	48,138			$45,011		$58,333	
17	Employee Discount			*16,976*			($5,347)		($6,918)	
18	**Total**		614,266	13,383,252			$16,008,845		$20,753,080	

*From UE 339

Docket No. UE 352
Exhibit PAC/502
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule 202, Renewable Adjustment Clause

December 2018

Purpose

This schedule recovers, between rate cases, the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

This adjustment is to recover the actual and forecasted revenue requirement associated with the prudently incurred costs of resources, including associated transmission, that are eligible under Senate Bill 838 (2007) and in service as of the date of the proposed rate change. The revenue requirement includes the actual return of and grossed up return on capital costs of the renewable energy source and associated transmission at the currently authorized rate of return, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs not captured in the Transition Adjustment Mechanism (TAM). The revenue requirement for Oregon will be calculated using the forecasted inter-jurisdictional allocation factors based on the same 12-month period used in the TAM. (D)

Applicable

To all Residential consumers and Nonresidential consumers. (C)

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge	
4	0.126 cents per kWh	(I)
5	0.126 cents per kWh	
15	0.096 cents per kWh	
23, 723	0.121 cents per kWh	
28, 728	0.124 cents per kWh	
30, 730	0.118 cents per kWh	
41, 741	0.122 cents per kWh	
47, 747	0.107 cents per kWh	
48, 748	0.107 cents per kWh	
50	0.079 cents per kWh	
51, 751	0.125 cents per kWh	
52, 752	0.096 cents per kWh	
53, 753	0.041 cents per kWh	
54, 754	0.070 cents per kWh	(I)

(continued)

Special Conditions

1. The Company will file this schedule by April 1 of each year, as necessary, for proposed charges relating to new eligible resources and updating all charges already included on this schedule.

2. The Company will make an update filing within eight (8) months of the date of the initial filing, or by December 1, to reflect then-current, prudently-incurred actual resource costs or forecasted costs where appropriate, if the cost elements of an eligible resource cannot be verified as of the date of the final round of testimony in the proceeding initiated April 1. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed charges before the January 1 effective date. The Company will be allowed to defer for later commission review and incorporation into rates the cost differences between the projected costs in the record and the updated prudently incurred cost elements if (a) such cost elements are higher than the projected costs in the record or (b) if actual capital costs cannot be verified until after December 1.

3. Costs recovered in this schedule will be allocated across customer classes using the applicable forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kilowatt-hour to each applicable rate schedule.

4. The dates and provisions listed in the special conditions above may be modified if approved by (N)
the Commission. (N)

Docket No. UE 352
Exhibit PAC/503
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed Price Changes

December 2018

RAC - October 1, 2019

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDING DECEMBER 31, 2019

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	506,345	5,401,764	$622,951	$5,618	$628,569	$629,757	$5,618	$635,375	$6,806	1.1%	$6,806	1.1%	1
2	**Total Residential**		506,345	5,401,764	$622,951	$5,618	$628,569	$629,757	$5,618	$635,375	$6,806	1.1%	$6,806	1.1%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	$126,459	$5,228	$131,687	$127,837	$5,228	$133,065	$1,378	1.1%	$1,378	1.1%	3
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	$181,356	$3,235	$184,591	$183,803	$3,235	$187,038	$2,447	1.4%	$2,447	1.3%	4
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	$108,386	$1,196	$109,582	$109,954	$1,196	$111,150	$1,568	1.5%	$1,568	1.4%	5
6	Large General Service >= 1,000 kW	48	195	3,221,037	$226,762	($9,688)	$217,074	$230,209	($9,688)	$220,521	$3,447	1.5%	$3,447	1.6%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859	$5,615	($154)	$5,461	$5,668	($154)	$5,514	$53	1.5%	$53	1.6%	7
8	Agricultural Pumping Service	41	7,982	222,624	$25,966	($1,230)	$24,736	$26,237	($1,230)	$25,007	$271	1.0%	$271	1.1%	8
9	**Total Commercial & Industrial**		100,164	7,933,350	$674,544	($1,413)	$673,131	$683,708	($1,413)	$682,295	$9,164	1.4%	$9,164	1.4%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,305	9,058	$1,167	$216	$1,383	$1,176	$216	$1,392	$9	0.8%	$9	0.7%	10
11	Street Lighting Service	50	225	7,713	$861	$169	$1,030	$867	$169	$1,036	$6	0.7%	$6	0.6%	11
12	Street Lighting Service HPS	51	815	19,940	$3,513	$721	$4,234	$3,538	$721	$4,259	$25	0.7%	$25	0.6%	12
13	Street Lighting Service	52	35	404	$53	$9	$62	$53	$9	$62	$0	0.0%	$0	0.0%	13
14	Street Lighting Service	53	273	9,678	$611	$121	$732	$615	$121	$736	$4	0.7%	$4	0.6%	14
15	Recreational Field Lighting	54	104	1,345	$112	$21	$133	$113	$21	$134	$1	0.9%	$1	0.8%	15
16	**Total Public Street Lighting**		7,757	48,138	$6,317	$1,257	$7,574	$6,362	$1,257	$7,619	$45	0.7%	$45	0.6%	16
17	**Total Sales before Emp. Disc. & AGA**		614,266	13,383,252	$1,303,812	$5,462	$1,309,274	$1,319,827	$5,462	$1,325,289	$16,015	1.2%	$16,015	1.2%	17
18	Employee Discount				($484)	($3)	($487)	($489)	($3)	($492)	($5)		($5)		18
19	**Total Sales with Emp. Disc**		614,266	13,383,252	$1,303,328	$5,459	$1,308,787	$1,319,338	$5,459	$1,324,797	$16,010	1.2%	$16,010	1.2%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		614,266	13,383,252	$1,305,767	$5,459	$1,311,226	$1,321,777	$5,459	$1,327,236	$16,010	1.2%	$16,010	1.2%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

RAC - December 1, 2019

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDING DECEMBER 31, 2019

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	506,345	5,401,764	$629,757	$5,618	$635,375	$638,562	$5,618	$644,180	$8,805	1.4%	$8,805	1.4%	1
2	**Total Residential**		506,345	5,401,764	$629,757	$5,618	$635,375	$638,562	$5,618	$644,180	$8,805	1.4%	$8,805	1.4%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	$127,837	$5,228	$133,065	$129,626	$5,228	$134,854	$1,789	1.4%	$1,789	1.3%	3
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	$183,803	$3,235	$187,038	$186,977	$3,235	$190,212	$3,174	1.7%	$3,174	1.7%	4
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	$109,954	$1,196	$111,150	$111,986	$1,196	$113,182	$2,032	1.9%	$2,032	1.8%	5
6	Large General Service >= 1,000 kW	48	195	3,221,037	$230,209	($9,688)	$220,521	$234,686	($9,688)	$224,998	$4,477	1.9%	$4,477	2.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859	$5,668	($154)	$5,514	$5,738	($154)	$5,584	$70	1.9%	$70	2.0%	7
8	Agricultural Pumping Service	41	7,982	222,624	$26,237	($1,230)	$25,007	$26,591	($1,230)	$25,361	$354	1.4%	$354	1.4%	8
9	**Total Commercial & Industrial**		100,164	7,933,350	$683,708	($1,413)	$682,295	$695,604	($1,413)	$694,191	$11,896	1.7%	$11,896	1.7%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,305	9,058	$1,176	$216	$1,392	$1,188	$216	$1,404	$12	1.0%	$12	0.9%	10
11	Street Lighting Service	50	225	7,713	$867	$169	$1,036	$875	$169	$1,044	$8	0.9%	$8	0.8%	11
12	Street Lighting Service HPS	51	815	19,940	$3,538	$721	$4,259	$3,571	$721	$4,292	$33	0.9%	$33	0.8%	12
13	Street Lighting Service	52	35	404	$53	$9	$62	$54	$9	$63	$1	1.9%	$1	1.6%	13
14	Street Lighting Service	53	273	9,678	$615	$121	$736	$620	$121	$741	$5	0.8%	$5	0.7%	14
15	Recreational Field Lighting	54	104	1,345	$113	$21	$134	$114	$21	$135	$1	0.9%	$1	0.8%	15
16	**Total Public Street Lighting**		7,757	48,138	$6,362	$1,257	$7,619	$6,422	$1,257	$7,679	$60	0.9%	$60	0.8%	16
17	**Total Sales before Emp. Disc. & AGA**		614,266	13,383,252	$1,319,827	$5,462	$1,325,289	$1,340,588	$5,462	$1,346,050	$20,761	1.6%	$20,761	1.6%	17
18	Employee Discount				($489)	($3)	($492)	($496)	($3)	($499)	($7)		($7)		18
19	**Total Sales with Emp. Disc**		614,266	13,383,252	$1,319,338	$5,459	$1,324,797	$1,340,092	$5,459	$1,345,551	$20,754	1.6%	$20,754	1.6%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		614,266	13,383,252	$1,321,777	$5,459	$1,327,236	$1,342,531	$5,459	$1,347,990	$20,754	1.6%	$20,754	1.6%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Docket No. UE 352
Exhibit PAC/504
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Monthly Billing Comparisons for October 1

December 2018

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.26	$20.38	$0.12	0.59%
200	$30.02	$30.27	$0.25	0.83%
300	$39.79	$40.18	$0.39	0.98%
400	$49.55	$50.07	$0.52	1.05%
500	$59.33	$59.98	$0.65	1.10%
600	$69.11	$69.88	$0.77	1.11%
700	$78.87	$79.78	$0.91	1.15%
800	$88.64	$89.68	$1.04	1.17%
900	**$98.40**	**$99.58**	**$1.18**	**1.20%**
950	$103.31	$104.54	$1.23	1.19%
1,000	$108.19	$109.48	$1.29	1.19%
1,100	$121.12	$122.55	$1.43	1.18%
1,200	$134.04	$135.61	$1.57	1.17%
1,300	$146.98	$148.66	$1.68	1.14%
1,400	$159.90	$161.72	$1.82	1.14%
1,500	$172.84	$174.78	$1.94	1.12%
1,600	$185.77	$187.85	$2.08	1.12%
2,000	$237.49	$240.08	$2.59	1.09%
3,000	$366.79	$370.68	$3.89	1.06%
4,000	$496.09	$501.28	$5.19	1.05%
5,000	$625.39	$631.88	$6.49	1.04%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$72	$81	$73	$82	0.87%	0.76%
	750	$100	$108	$100	$109	0.94%	0.86%
	1,000	$127	$136	$128	$137	0.98%	0.92%
	1,500	$181	$190	$183	$192	1.03%	0.98%
10	1,000	$127	$136	$128	$137	0.98%	0.92%
	2,000	$236	$244	$238	$247	1.06%	1.02%
	3,000	$345	$353	$348	$357	1.09%	1.06%
	4,000	$437	$446	$442	$451	1.14%	1.12%
20	4,000	$464	$473	$469	$478	1.07%	1.06%
	6,000	$648	$657	$656	$664	1.15%	1.14%
	8,000	$832	$841	$842	$851	1.20%	1.19%
	10,000	$1,017	$1,026	$1,029	$1,038	1.23%	1.21%
30	9,000	$978	$987	$990	$999	1.15%	1.14%
	12,000	$1,255	$1,264	$1,270	$1,279	1.19%	1.18%
	15,000	$1,532	$1,540	$1,550	$1,559	1.22%	1.21%
	18,000	$1,808	$1,817	$1,831	$1,839	1.24%	1.23%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$80	$72	$80	0.89%	0.78%
	750	$97	$106	$98	$107	0.95%	0.89%
	1,000	$124	$133	$125	$134	1.01%	0.94%
	1,500	$177	$186	$179	$188	1.06%	1.01%
10	1,000	$124	$133	$125	$134	1.01%	0.94%
	2,000	$230	$239	$232	$241	1.08%	1.05%
	3,000	$336	$345	$340	$348	1.11%	1.08%
	4,000	$426	$435	$431	$440	1.17%	1.15%
20	4,000	$452	$461	$457	$466	1.10%	1.08%
	6,000	$632	$641	$639	$648	1.18%	1.17%
	8,000	$811	$820	$821	$830	1.23%	1.22%
	10,000	$991	$1,000	$1,003	$1,012	1.26%	1.25%
30	9,000	$954	$963	$965	$974	1.18%	1.16%
	12,000	$1,223	$1,232	$1,238	$1,247	1.22%	1.21%
	15,000	$1,493	$1,501	$1,511	$1,520	1.25%	1.25%
	18,000	$1,762	$1,771	$1,784	$1,793	1.27%	1.27%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$353	$357	1.09%
	4,500	$467	$473	1.23%
	7,500	$695	$705	1.38%
31	6,200	$709	$717	1.12%
	9,300	$945	$957	1.26%
	15,500	$1,417	$1,437	1.40%
40	8,000	$910	$920	1.12%
	12,000	$1,214	$1,229	1.26%
	20,000	$1,823	$1,848	1.40%
60	12,000	$1,357	$1,372	1.13%
	18,000	$1,813	$1,836	1.27%
	30,000	$2,709	$2,747	1.41%
80	16,000	$1,797	$1,817	1.14%
	24,000	$2,399	$2,429	1.28%
	40,000	$3,588	$3,639	1.42%
100	20,000	$2,238	$2,263	1.14%
	30,000	$2,981	$3,019	1.29%
	50,000	$4,468	$4,532	1.43%
200	40,000	$4,381	$4,433	1.17%
	60,000	$5,868	$5,945	1.31%
	100,000	$8,842	$8,970	1.44%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$454	$460	1.26%
	6,000	$558	$566	1.37%
	7,500	$662	$672	1.45%
31	9,300	$912	$924	1.30%
	12,400	$1,127	$1,143	1.41%
	15,500	$1,342	$1,362	1.47%
40	12,000	$1,169	$1,185	1.31%
	16,000	$1,447	$1,468	1.41%
	20,000	$1,725	$1,751	1.48%
60	18,000	$1,744	$1,767	1.32%
	24,000	$2,154	$2,185	1.42%
	30,000	$2,561	$2,599	1.50%
80	24,000	$2,304	$2,335	1.33%
	32,000	$2,847	$2,888	1.44%
	40,000	$3,390	$3,441	1.51%
100	30,000	$2,862	$2,900	1.34%
	40,000	$3,540	$3,591	1.44%
	50,000	$4,218	$4,282	1.51%
200	60,000	$5,612	$5,689	1.37%
	80,000	$6,969	$7,071	1.47%
	100,000	$8,326	$8,453	1.53%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,666	$2,691	0.91%
	30,000	$3,267	$3,304	1.12%
	50,000	$4,469	$4,529	1.36%
200	40,000	$4,688	$4,737	1.04%
	60,000	$5,890	$5,963	1.24%
	100,000	$8,293	$8,415	1.47%
300	60,000	$6,881	$6,953	1.06%
	90,000	$8,683	$8,792	1.26%
	150,000	$12,287	$12,470	1.48%
400	80,000	$8,954	$9,051	1.09%
	120,000	$11,357	$11,503	1.28%
	200,000	$16,163	$16,406	1.50%
500	100,000	$11,059	$11,180	1.10%
	150,000	$14,063	$14,245	1.30%
	250,000	$20,070	$20,374	1.51%
600	120,000	$13,163	$13,309	1.11%
	180,000	$16,768	$16,987	1.30%
	300,000	$23,977	$24,342	1.52%
800	160,000	$17,372	$17,567	1.12%
	240,000	$22,178	$22,470	1.32%
	400,000	$31,791	$32,277	1.53%
1000	200,000	$21,581	$21,824	1.13%
	300,000	$27,589	$27,954	1.32%
	500,000	$39,604	$40,212	1.53%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	30,000	$3,204	$3,241	1.14%
	40,000	$3,794	$3,842	1.28%
	50,000	$4,383	$4,444	1.39%
200	60,000	$5,780	$5,853	1.26%
	80,000	$6,959	$7,056	1.40%
	100,000	$8,138	$8,259	1.49%
300	90,000	$8,515	$8,624	1.28%
	120,000	$10,283	$10,429	1.42%
	150,000	$12,052	$12,234	1.51%
400	120,000	$11,155	$11,301	1.31%
	160,000	$13,513	$13,708	1.44%
	200,000	$15,871	$16,114	1.53%
500	150,000	$13,808	$13,990	1.32%
	200,000	$16,755	$16,998	1.45%
	250,000	$19,702	$20,006	1.54%
600	180,000	$16,461	$16,680	1.33%
	240,000	$19,998	$20,289	1.46%
	300,000	$23,534	$23,899	1.55%
800	240,000	$21,766	$22,058	1.34%
	320,000	$26,482	$26,871	1.47%
	400,000	$31,197	$31,684	1.56%
1000	300,000	$27,072	$27,437	1.35%
	400,000	$32,966	$33,453	1.47%
	500,000	$38,861	$39,468	1.56%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$193	$222	$155	$196	$224	$155	1.30%	1.13%	0.00%
	3,000	$290	$319	$155	$294	$322	$155	1.30%	1.18%	0.00%
	5,000	$483	$512	$155	$490	$518	$155	1.30%	1.23%	0.00%
Three Phase										
20	4,000	$387	$444	$309	$392	$449	$309	1.30%	1.13%	0.00%
	6,000	$580	$637	$309	$588	$645	$309	1.30%	1.18%	0.00%
	10,000	$967	$1,024	$309	$979	$1,036	$309	1.30%	1.23%	0.00%
100	20,000	$1,933	$2,219	$1,349	$1,958	$2,244	$1,349	1.30%	1.13%	0.00%
	30,000	$2,900	$3,186	$1,349	$2,938	$3,223	$1,349	1.30%	1.18%	0.00%
	50,000	$4,833	$5,119	$1,349	$4,896	$5,182	$1,349	1.30%	1.23%	0.00%
300	60,000	$5,800	$6,657	$3,409	$5,875	$6,732	$3,409	1.30%	1.13%	0.00%
	90,000	$8,700	$9,557	$3,409	$8,813	$9,670	$3,409	1.30%	1.18%	0.00%
	150,000	$14,500	$15,357	$3,409	$14,688	$15,545	$3,409	1.30%	1.23%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$281	$308	$155	$285	$312	$155	1.34%	1.22%	0.00%
	4,000	$374	$402	$155	$379	$407	$155	1.34%	1.25%	0.00%
	5,000	$468	$496	$155	$474	$502	$155	1.34%	1.27%	0.00%
Three Phase										
20	6,000	$562	$617	$309	$569	$625	$309	1.34%	1.22%	0.00%
	8,000	$749	$804	$309	$759	$814	$309	1.34%	1.25%	0.00%
	10,000	$936	$991	$309	$949	$1,004	$309	1.34%	1.27%	0.00%
100	30,000	$2,808	$3,085	$1,339	$2,846	$3,123	$1,339	1.34%	1.22%	0.00%
	40,000	$3,744	$4,021	$1,339	$3,794	$4,071	$1,339	1.34%	1.25%	0.00%
	50,000	$4,680	$4,957	$1,339	$4,743	$5,020	$1,339	1.34%	1.27%	0.00%
300	90,000	$8,424	$9,254	$3,399	$8,538	$9,368	$3,399	1.34%	1.22%	0.00%
	120,000	$11,233	$12,063	$3,399	$11,383	$12,213	$3,399	1.34%	1.25%	0.00%
	150,000	$14,041	$14,871	$3,399	$14,229	$15,059	$3,399	1.34%	1.27%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$26,861	$27,192	1.23%
	500,000	$38,346	$38,897	1.44%
	650,000	$46,959	$47,675	1.53%
2,000	600,000	$53,290	$53,951	1.24%
	1,000,000	$74,009	$75,111	1.49%
	1,300,000	$90,410	$91,843	1.58%
6,000	1,800,000	$154,637	$156,621	1.28%
	3,000,000	$220,243	$223,549	1.50%
	3,900,000	$269,448	$273,746	1.60%
12,000	3,600,000	$307,949	$311,917	1.29%
	6,000,000	$439,162	$445,775	1.51%
	7,800,000	$537,572	$546,168	1.60%

Notes:

On-Peak kWh	64.49%
Off-Peak kWh	35.51%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$25,410	$25,740	1.30%
	500,000	$36,076	$36,627	1.53%
	650,000	$44,076	$44,792	1.63%
2,000	600,000	$50,345	$51,007	1.31%
	1,000,000	$69,428	$70,530	1.59%
	1,300,000	$84,602	$86,035	1.69%
6,000	1,800,000	$145,401	$147,385	1.36%
	3,000,000	$206,099	$209,406	1.60%
	3,900,000	$251,623	$255,921	1.71%
12,000	3,600,000	$289,448	$293,416	1.37%
	6,000,000	$410,844	$417,456	1.61%
	7,800,000	$501,891	$510,487	1.71%

Notes:

On-Peak kWh	61.36%
Off-Peak kWh	38.64%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	500,000	$35,770	$36,321	1.54%
	650,000	$43,221	$43,937	1.66%
2,000	1,000,000	$68,404	$69,507	1.61%
	1,300,000	$82,480	$83,913	1.74%
6,000	3,000,000	$203,204	$206,510	1.63%
	3,900,000	$245,431	$249,729	1.75%
12,000	6,000,000	$404,260	$410,872	1.64%
	7,800,000	$488,714	$497,311	1.76%
50,000	25,000,000	$1,677,614	$1,705,166	1.64%
	32,500,000	$2,029,508	$2,065,326	1.76%

Notes:
On-Peak kWh 56.79%
Off-Peak kWh 43.21%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Docket No. UE 352
Exhibit PAC/505
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Monthly Billing Comparisons for December 1

December 2018

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.38	$20.55	$0.17	0.83%
200	$30.27	$30.61	$0.34	1.12%
300	$40.18	$40.68	$0.50	1.24%
400	$50.07	$50.74	$0.67	1.34%
500	$59.98	$60.82	$0.84	1.40%
600	$69.88	$70.89	$1.01	1.45%
700	$79.78	$80.96	$1.18	1.48%
800	$89.68	$91.02	$1.34	1.49%
900	$99.58	$101.09	$1.51	1.52%
950	$104.54	$106.14	$1.60	1.53%
1,000	$109.48	$111.16	$1.68	1.53%
1,100	$122.55	$124.39	$1.84	1.50%
1,200	$135.61	$137.61	$2.00	1.47%
1,300	$148.66	$150.84	$2.18	1.47%
1,400	$161.72	$164.07	$2.35	1.45%
1,500	$174.78	$177.31	$2.53	1.45%
1,600	$187.85	$190.54	$2.69	1.43%
2,000	$240.08	$243.44	$3.36	1.40%
3,000	$370.68	$375.72	$5.04	1.36%
4,000	$501.28	$508.00	$6.72	1.34%
5,000	$631.88	$640.28	$8.40	1.33%

* Net rate including Schedules 91, 98, 199, 290 and 297.
Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price Single Phase	Present Price Three Phase	Proposed Price Single Phase	Proposed Price Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
5	500	$73	$82	$74	$83	1.11%	0.99%
	750	$100	$109	$102	$111	1.20%	1.12%
	1,000	$128	$137	$130	$138	1.27%	1.18%
	1,500	$183	$192	$186	$194	1.33%	1.26%
10	1,000	$128	$137	$130	$138	1.27%	1.18%
	2,000	$238	$247	$241	$250	1.36%	1.31%
	3,000	$348	$357	$353	$362	1.39%	1.36%
	4,000	$442	$451	$448	$457	1.46%	1.43%
20	4,000	$469	$478	$475	$484	1.38%	1.35%
	6,000	$656	$664	$665	$674	1.48%	1.46%
	8,000	$842	$851	$855	$864	1.54%	1.52%
	10,000	$1,029	$1,038	$1,045	$1,054	1.57%	1.56%
30	9,000	$990	$999	$1,004	$1,013	1.47%	1.46%
	12,000	$1,270	$1,279	$1,289	$1,298	1.53%	1.52%
	15,000	$1,550	$1,559	$1,575	$1,583	1.56%	1.56%
	18,000	$1,831	$1,839	$1,860	$1,868	1.59%	1.58%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$72	$80	$72	$81	1.12%	1.01%
	750	$98	$107	$100	$108	1.24%	1.13%
	1,000	$125	$134	$127	$136	1.29%	1.20%
	1,500	$179	$188	$181	$190	1.35%	1.30%
10	1,000	$125	$134	$127	$136	1.29%	1.20%
	2,000	$232	$241	$236	$244	1.39%	1.34%
	3,000	$340	$348	$345	$353	1.43%	1.39%
	4,000	$431	$440	$437	$446	1.50%	1.47%
20	4,000	$457	$466	$464	$472	1.41%	1.39%
	6,000	$639	$648	$649	$658	1.52%	1.50%
	8,000	$821	$830	$834	$843	1.58%	1.56%
	10,000	$1,003	$1,012	$1,020	$1,028	1.61%	1.60%
30	9,000	$965	$974	$980	$988	1.51%	1.50%
	12,000	$1,238	$1,247	$1,258	$1,266	1.57%	1.56%
	15,000	$1,511	$1,520	$1,536	$1,544	1.61%	1.60%
	18,000	$1,784	$1,793	$1,814	$1,822	1.63%	1.62%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$357	$362	1.39%
	4,500	$473	$480	1.58%
	7,500	$705	$717	1.77%
31	6,200	$717	$727	1.43%
	9,300	$957	$972	1.61%
	15,500	$1,437	$1,462	1.79%
40	8,000	$920	$933	1.44%
	12,000	$1,229	$1,249	1.62%
	20,000	$1,848	$1,882	1.79%
60	12,000	$1,372	$1,392	1.45%
	18,000	$1,836	$1,866	1.63%
	30,000	$2,747	$2,797	1.81%
80	16,000	$1,817	$1,844	1.46%
	24,000	$2,429	$2,469	1.64%
	40,000	$3,639	$3,706	1.82%
100	20,000	$2,263	$2,296	1.47%
	30,000	$3,019	$3,069	1.65%
	50,000	$4,532	$4,615	1.83%
200	40,000	$4,433	$4,499	1.50%
	60,000	$5,945	$6,044	1.67%
	100,000	$8,970	$9,136	1.85%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$460	$467	1.63%
	6,000	$566	$576	1.76%
	7,500	$672	$684	1.85%
31	9,300	$924	$939	1.67%
	12,400	$1,143	$1,163	1.80%
	15,500	$1,362	$1,388	1.89%
40	12,000	$1,185	$1,205	1.68%
	16,000	$1,468	$1,494	1.81%
	20,000	$1,751	$1,784	1.89%
60	18,000	$1,767	$1,796	1.69%
	24,000	$2,185	$2,224	1.82%
	30,000	$2,599	$2,649	1.91%
80	24,000	$2,335	$2,375	1.70%
	32,000	$2,888	$2,941	1.84%
	40,000	$3,441	$3,507	1.93%
100	30,000	$2,900	$2,950	1.72%
	40,000	$3,591	$3,657	1.85%
	50,000	$4,282	$4,365	1.94%
200	60,000	$5,689	$5,789	1.75%
	80,000	$7,071	$7,204	1.88%
	100,000	$8,453	$8,619	1.96%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	20,000	$2,691	$2,722	1.17%
	30,000	$3,304	$3,351	1.43%
	50,000	$4,529	$4,608	1.74%
200	40,000	$4,737	$4,800	1.33%
	60,000	$5,963	$6,057	1.59%
	100,000	$8,415	$8,572	1.87%
300	60,000	$6,953	$7,048	1.36%
	90,000	$8,792	$8,934	1.61%
	150,000	$12,470	$12,706	1.90%
400	80,000	$9,051	$9,177	1.39%
	120,000	$11,503	$11,692	1.64%
	200,000	$16,406	$16,722	1.92%
500	100,000	$11,180	$11,338	1.41%
	150,000	$14,245	$14,481	1.66%
	250,000	$20,374	$20,768	1.93%
600	120,000	$13,309	$13,498	1.42%
	180,000	$16,987	$17,270	1.67%
	300,000	$24,342	$24,814	1.94%
800	160,000	$17,567	$17,819	1.44%
	240,000	$22,470	$22,848	1.68%
	400,000	$32,277	$32,907	1.95%
1000	200,000	$21,824	$22,140	1.44%
	300,000	$27,954	$28,426	1.69%
	500,000	$40,212	$41,000	1.96%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	30,000	$3,241	$3,288	1.46%
	40,000	$3,842	$3,905	1.64%
	50,000	$4,444	$4,523	1.77%
200	60,000	$5,853	$5,947	1.62%
	80,000	$7,056	$7,182	1.79%
	100,000	$8,259	$8,417	1.91%
300	90,000	$8,624	$8,766	1.64%
	120,000	$10,429	$10,618	1.81%
	150,000	$12,234	$12,470	1.93%
400	120,000	$11,301	$11,490	1.67%
	160,000	$13,708	$13,960	1.84%
	200,000	$16,114	$16,429	1.96%
500	150,000	$13,990	$14,227	1.69%
	200,000	$16,998	$17,314	1.85%
	250,000	$20,006	$20,400	1.97%
600	180,000	$16,680	$16,963	1.70%
	240,000	$20,289	$20,667	1.86%
	300,000	$23,899	$24,372	1.98%
800	240,000	$22,058	$22,436	1.71%
	320,000	$26,871	$27,375	1.88%
	400,000	$31,684	$32,314	1.99%
1000	300,000	$27,437	$27,909	1.72%
	400,000	$33,453	$34,083	1.88%
	500,000	$39,468	$40,256	2.00%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$196	$224	$155	$199	$228	$155	1.67%	1.46%	0.00%
	3,000	$294	$322	$155	$299	$327	$155	1.67%	1.53%	0.00%
	5,000	$490	$518	$155	$498	$526	$155	1.67%	1.58%	0.00%
Three Phase										
20	4,000	$392	$449	$309	$398	$455	$309	1.67%	1.46%	0.00%
	6,000	$588	$645	$309	$597	$654	$309	1.67%	1.52%	0.00%
	10,000	$979	$1,036	$309	$996	$1,053	$309	1.67%	1.58%	0.00%
100	20,000	$1,958	$2,244	$1,349	$1,991	$2,277	$1,349	1.67%	1.46%	0.00%
	30,000	$2,938	$3,223	$1,349	$2,987	$3,272	$1,349	1.67%	1.52%	0.00%
	50,000	$4,896	$5,182	$1,349	$4,978	$5,264	$1,349	1.67%	1.58%	0.00%
300	60,000	$5,875	$6,732	$3,409	$5,973	$6,831	$3,409	1.67%	1.46%	0.00%
	90,000	$8,813	$9,670	$3,409	$8,960	$9,817	$3,409	1.67%	1.52%	0.00%
	150,000	$14,688	$15,545	$3,409	$14,934	$15,791	$3,409	1.67%	1.58%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$285	$312	$155	$290	$317	$155	1.73%	1.57%	0.00%
	4,000	$379	$407	$155	$386	$414	$155	1.73%	1.61%	0.00%
	5,000	$474	$502	$155	$483	$510	$155	1.73%	1.63%	0.00%
Three Phase										
20	6,000	$569	$625	$309	$579	$634	$309	1.73%	1.57%	0.00%
	8,000	$759	$814	$309	$772	$827	$309	1.73%	1.61%	0.00%
	10,000	$949	$1,004	$309	$965	$1,020	$309	1.73%	1.63%	0.00%
100	30,000	$2,846	$3,123	$1,339	$2,895	$3,172	$1,339	1.73%	1.57%	0.00%
	40,000	$3,794	$4,071	$1,339	$3,860	$4,137	$1,339	1.73%	1.61%	0.00%
	50,000	$4,743	$5,020	$1,339	$4,825	$5,102	$1,339	1.73%	1.63%	0.00%
300	90,000	$8,538	$9,368	$3,399	$8,685	$9,515	$3,399	1.73%	1.57%	0.00%
	120,000	$11,383	$12,213	$3,399	$11,580	$12,410	$3,399	1.73%	1.61%	0.00%
	150,000	$14,229	$15,059	$3,399	$14,475	$15,305	$3,399	1.73%	1.63%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$27,192	$27,621	1.58%
	500,000	$38,897	$39,613	1.84%
	650,000	$47,675	$48,606	1.95%
2,000	600,000	$53,951	$54,810	1.59%
	1,000,000	$75,111	$76,542	1.91%
	1,300,000	$91,843	$93,704	2.03%
6,000	1,800,000	$156,621	$159,198	1.65%
	3,000,000	$223,549	$227,845	1.92%
	3,900,000	$273,746	$279,330	2.04%
12,000	3,600,000	$311,917	$317,071	1.65%
	6,000,000	$445,775	$454,365	1.93%
	7,800,000	$546,168	$557,335	2.04%

Notes:

On-Peak kWh	64.49%
Off-Peak kWh	35.51%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$25,740	$26,170	1.67%
	500,000	$36,627	$37,343	1.95%
	650,000	$44,792	$45,723	2.08%
2,000	600,000	$51,007	$51,866	1.68%
	1,000,000	$70,530	$71,962	2.03%
	1,300,000	$86,035	$87,896	2.16%
6,000	1,800,000	$147,385	$149,962	1.75%
	3,000,000	$209,406	$213,701	2.05%
	3,900,000	$255,921	$261,505	2.18%
12,000	3,600,000	$293,416	$298,570	1.76%
	6,000,000	$417,456	$426,047	2.06%
	7,800,000	$510,487	$521,654	2.19%

Notes:

On-Peak kWh	61.36%
Off-Peak kWh	38.64%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	500,000	$36,321	$37,037	1.97%
	650,000	$43,937	$44,867	2.12%
2,000	1,000,000	$69,507	$70,938	2.06%
	1,300,000	$83,913	$85,774	2.22%
6,000	3,000,000	$206,510	$210,805	2.08%
	3,900,000	$249,729	$255,313	2.24%
12,000	6,000,000	$410,872	$419,463	2.09%
	7,800,000	$497,311	$508,478	2.25%
50,000	25,000,000	$1,705,166	$1,740,959	2.10%
	32,500,000	$2,065,326	$2,111,857	2.25%

Notes:

On-Peak kWh	56.79%
Off-Peak kWh	43.21%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.