Rocky Mountain Power
Docket No. 20-035-04
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Joelle R. Steward

May 2020

I. INTRODUCTION OF WITNESS AND QUALIFICATIONS

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

A. My name is Joelle R. Steward. My business address is 1407 West North Temple, Salt Lake City, Utah 84116. My present position is Vice President, Regulation for Rocky Mountain Power.

Q. Please summarize your education and business experience.

A. I have a B.A. degree in Political Science from the University of Oregon and an M.A. in Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as a Regulatory Manager, responsible for all regulatory filings and proceedings in Oregon. On February 14, 2012, I assumed responsibilities overseeing cost of service and pricing for PacifiCorp. In May 2015, I assumed broader oversight over Rocky Mountain Power's regulatory affairs in addition to the cost of service and pricing responsibilities; and in 2017 I assumed my current role as Vice President, Regulation for Rocky Mountain Power.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified on various matters in the states of Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I provide an overview of Rocky Mountain Power's current filing and support the Company's policy positions throughout this filing. As explained in the testimony of Mr. Gary W. Hoogeveen, the Company has made a concerted effort to manage its controllable costs since the Company's last general rate case in 2014 ("2014 Rate Case")[1] and to pursue innovative opportunities like the Energy Imbalance Market ("EIM") and Energy Vision 2020 and provide customers the opportunity to choose renewable resources for electric service. While requesting an increase in the overall revenue requirement, this rate case filing reflects the Company's prudent and efficient management of its costs that has allowed it to stay out of a rate case for six years while continuing to invest in the system and adhering to the core principle of providing safe, reliable, and affordable service for customers. This filing brings to customers the benefits of low-cost new and repowered wind resources that lower net power costs ("NPC"), along with the production tax credits ("PTCs"), a complete incorporation of the savings of federal Tax Cut and Jobs Act ("TCJA"), new transmission investments to support and strengthen the bulk power system, and a modernization of rate designs to provide better transparency and enable customers to make more informed decisions to benefit themselves and the system.

Recognizing any rate increase at this time in particular can be challenging for customers in light of the economic impact of the COVID-19 public health emergency,

[1] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184 Report and Order Approving the Settlement Stipulation dated June 25, 2014. (Aug. 29, 2014).

the Company has reflected a number of ratemaking measures that mitigate the requested revenue requirement rate increase. Additionally, the Company is proposing to continue to pass back TCJA deferred tax savings through a rate credit to offset, in part, the bill impacts and create a phase-in of the revenue requirement increase over three years. The requested revenue requirement increase in this general rate case filing is $95.8 million, or 4.8 percent. However, with the Company's proposed phase-in, the tax credit will mitigate the first-year increase by $44.3 million; thus, beginning on January 1, 2021, there will be an overall increase of 2.6 percent. Beginning January 1, 2022, the tax credit will be reduced to $22.2 million for a net increase of approximately 1.1 percent. Finally, on January 1, 2023, the tax credit will have been fully refunded to customers, resulting in a net increase of approximately 1.1 percent.

The requested revenue requirement increase has been significantly mitigated through (1) implementation of the settlement agreement in the TCJA proceeding,[2] which included agreement on the use of the balance in the Sustainable Transportation and Energy Plan ("STEP") regulatory liability account, to buy-down the undepreciated plant balance of certain coal-fired generation units, which reduces depreciation expense, (2) use of a portion of the TCJA deferred tax benefits to pay off certain regulatory assets and further depreciate the Dave Johnston plant balance, which lowers on-going expense, and (3) creation of a regulatory asset to extend the recovery for Jim Bridger Units 1 and 2 to reduce depreciation expense until future STEP funds are accumulated to buy-down the plant balances when the units are retired. Altogether

[2] *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018"*, Docket No. 17-035-69 (Dec. 21, 2017).

these combined actions reduce the requested revenue requirement increase by approximately $66.1 million, or 3 percent. The remaining TCJA tax benefit balance of approximately $66.5 million will be refunded to customers over the next two years, with the gradual phase-down of the credit as explained above, to provide better rate certainty for customers.

Q. How is your direct testimony structured?

A. Section III of my testimony provides an overview of the Company's last rate case filing. Section IV provides an overview of this rate case filing, including a discussion of primary drivers. Section V discusses the rate mitigation proposals included in this rate request. Section VI discusses the Company's decision to discontinue operations at Cholla Unit 4 and to remove it from service. Section VII discusses proposed enhancements to the Company's Subscriber Solar Program. Section VIII discusses the proposed cost recovery mechanism for costs to implement the wildland fire protection plan required by Utah House Bill ("HB") 66.

Q. Please summarize the recommendations you make in your direct testimony.

A. I recommend that the Public Service Commission of Utah ("Commission"):

- Authorize rates to recover an overall Utah revenue requirement of $2.097 billion, which is an increase of $95.8 million, or 4.8 percent, to current base rates. The support for the overall increase is set forth in my testimony and the testimony of the other Company witnesses.
- Approve a refund of $44.3 million in 2021 and $22.2 million in 2022 of the TCJA deferred tax benefits under Electric Service Schedule No. 197 – Federal Tax Act Adjustment ("Schedule 197"), to mitigate the bill impacts from the revenue

requirement increase in this case, as discussed in my testimony and the testimonies of Mr. Steven R. McDougal and Mr. Robert M. Meredith.

- Approve the rate mitigation proposals, including application of the remaining TCJA deferred tax benefits to buy down plant balances for the Dave Johnston generating plant and pay off four regulatory assets; creation of a regulatory asset for the recovery of Jim Bridger Units 1 and 2; and use the balance in the STEP regulatory liability account to pay down the undepreciated plant balance of Cholla Unit 4 and a portion of Craig Units 1 and 2 that I describe in my testimony;
- Approve as prudent the Company's request to include the incremental additions to the Company's rate base, including Energy Vision 2020, the repowering of Leaning Juniper and Foote Creek I, the Pryor Mountain Wind Project, the installation of selective catalytic reduction retrofits on certain generating units, the conversion of Naughton Unit 3 to gas, and the Utah Advanced Meter Infrastructure ("AMI") for a total 2021 Utah rate base of approximately $7.8 billion, as discussed in the testimony of various witnesses in this rate case.
- Approve an overall cost of capital of 7.7 percent, which is comprised of a capital structure of 53.67 percent equity, 46.32 percent long-term debt, and 0.01 percent preferred stock as supported by Ms. Nikki L. Kobliha; and a return on equity ("ROE") of 10.2 percent as supported by Ms. Ann E. Bulkley.
- Approve Base Energy Balancing Account ("EBA") Costs of $1.421 billion on a total-company basis and $619.2 million on a Utah-allocated basis, included in overall revenue requirement, and a true-up of PTCs in the EBA, as discussed in the testimony of Mr. David G. Webb.

- Approve the creation of a regulatory asset for recovery of unrecovered costs after closure of Cholla Unit 4, which the Company is retiring at the end of 2020, as supported in the testimony of Mr. Rick T. Link and Mr. McDougal.
- Approve the Company's proposed Wildland Fire Mitigation Balancing Account as supported in the testimony of Mr. McDougal.
- Approve the Company's proposed changes to its Subscriber Solar Program as supported in the testimony of Mr. William J. Comeau.
- Approve the update to certain customer service charges on Schedule 300, and a 50 cent bill credit for customers who opt out of receiving paper bills as set forth in the testimony of Ms. Melissa S. Nottingham.
- Approve the innovative and equitable cost of service, rate spread and rate design proposals, set forth in the testimony of Mr. Meredith.

III. PREVIOUS RATE CASE HISTORY

Q. Please discuss the Company's most recent general rate case and its outcome.

A. The Company's efficient management of costs has allowed it to avoid the need to file a general rate case for six years. On January 3, 2014, the Company filed its 2014 Rate Case requesting an increase in revenues from Utah operations for an overall price change of 4.0 percent or $76.3 million. The Commission approved a comprehensive, multi-year, uncontested settlement stipulation, authorizing a two-step rate increase of $35.0 million effective September 1, 2014, and a rate increase of $19.2 million effective September 1, 2015.[3]

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[3] Docket No. 13-035-184, Report and Order Approving the Settlement Stipulation dated June 25, 2014, Ordering Paragraphs 2, 4.

Q. What is the Company's overall retail average rate change in Utah since 2014?

A. Since the conclusion of the Company's 2014 Rate Case with rates effective September 1, 2015, for the second of the two-step approved increase, the Company's Utah customers have seen an overall average retail rate decrease of nearly 4 percent, from 8.40 cents per kilowatt-hour ("kWh") for the 12-month period ending December 31, 2016, to 8.09 cents per kWh for the 12-month period ending December 31, 2019. In contrast, inflation saw a 6.4 percent increase over this same time period.[4] Even with the Company's proposed increase in this case, overall average rates will continue to be less than 2016, pre-tax reform, at 8.30 cents per kWh.

IV. OVERVIEW OF RATE CASE

Q. What is the purpose of this Section of your direct testimony?

A. In this section of my testimony, I explain the various components of the Company's rate case filing. I also explain the primary drivers of the requested increase in the Company's rates.

Q. What test period is the Company using in this rate proceeding?

A. On March 6, 2020, the Commission issued an order approving the Company's requested test period in this case for the 12 months ending December 31, 2021, which is based on the 12-month historical period ended December 31, 2019.[5] The testimony of Mr. McDougal discusses the development of the test period.

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4 *CPI Inflation Calculator*, Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm (comparing January 2016 to January 2019).

5 *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations,* Docket No. 20-035-04, Order Approving Test Period (Mar. 6, 2020).

Q. What rate of return is the Company requesting in this case?

A. The Company is requesting approval of an overall rate of return of 7.7 percent. The overall rate of return reflects a 10.2 percent ROE as supported by Ms. Bulkley. As explained by Ms. Kobliha, PacifiCorp is requesting approval of a capital structure that is comprised of 53.67 percent equity, 46.32 percent long-term debt, and 0.01 percent of preferred stock. Mr. McDougal applies the overall rate of return in the calculation of the Company's Utah-allocated revenue requirement.

Q. Is the Company using a new inter-jurisdictional allocation methodology in this rate case?

A. Yes. On December 3, 2019, the Company filed with the Commission an application for approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2020 Protocol").[6] The Commission approved the Company's application on April 15, 2020, finding it just and reasonable and within the public interest.[7] As explained by Mr. McDougal, the Company used the 2020 Protocol to develop the revenue requirement in this proceeding, which for allocating costs in this case, is consistent with the 2017 Protocol.

Q. Please describe the primary drivers of Rocky Mountain Power's rate request.

A. The primary drivers of the Company's general rate request are capital additions and updated depreciation rates. I discuss each of these drivers in more detail below.

[6] *Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42 (Dec. 3, 2019).
[7] Docket No. 19-035-42, Order Approving 2020 Protocol.

Q. Please describe the capital additions drivers in this rate request.

A. The major driver is the Company's capital investment since the last rate case and through the calendar year 2021 test period. The most significant investments in this proceeding are: (1) the Energy Vision 2020 projects; (2) repowering projects for Leaning Juniper and Foote Creek I; and (3) the new Pryor Mountain Wind Project. Other capital additions include selective catalytic reduction retrofit projects at Jim Bridger Units 3 and 4 and our partner-operated plants Craig Unit 2 and Hayden Unit 2, the conversion of Naughton Unit 3 to natural gas, various transmission projects and the initial phase of the Utah AMI Project. These capital investments are more fully discussed in the testimonies of Mr. Link, Mr. Robert Van Engelenhoven, Mr. Timothy J. Hemstreet, Mr. James C. Owen, Mr. Richard A. Vail, and Mr. Curtis B. Mansfield.

Q. What are the major components of Energy Vision 2020?

A. Energy Vision 2020 consists of two major components, both of which are included in this case: (1) wind repowering ("Repowering Projects")[8]; and (2) investments in new wind and transmission ("New Wind and Transmission Projects").

Q. Please describe the Repowering Projects.

A. As explained in the testimony of Mr. Hemstreet, the Repowering Projects involve upgrading PacifiCorp's existing wind facilities to increase the amount of zero-fuel-cost energy they produce. By complying with federal tax requirements for wind repowering and completing the work by the end of 2020, the Company is able to renew the federal PTCs on all repowered wind facilities for another 10 years. The Commission approved

[8] "Repowering Projects" refers to the repowering of the following wind facilities: Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, Dunlap, Marengo I, Marengo II, and Goodnoe Hills.

a resource decision for the repowering of 11 of the Company-owned wind facilities in in Docket No. 17-035-39.[9] In its decision, the Commission approved projected costs for each of the Repowering Projects. In this general rate case filing, the Company provides an update on the status of each project, including support for project costs and demonstrates that the costs associated with these investments are prudent and reasonable. For further details regarding the repowering projects, see Mr. Hemstreet's testimony.

Q. Is the Company requesting recovery of the costs to repower two additional wind facilities in this proceeding?

A. Yes. The Company is seeking approval for the costs to repower two additional Company-owned wind facilities—Leaning Juniper and Foote Creek I. As described in the testimony of Mr. Hemstreet and Mr. Link, the Leaning Juniper and Foote Creek I projects produce net customer benefits across a range of price-policy scenarios. The upgrades to repower Leaning Juniper and Foote Creek I are prudent and reasonable and within the public interest. With respect to the repowering the Leaning Juniper and Foote Creek I wind facilities, Mr. Hemstreet provides details of each repowering project in his testimony and Mr. Link provides the economic analysis of the projects in his testimony.

Q. What is the status of the construction of the Energy Vision 2020 Repowering Projects, Leaning Juniper project, and the Foote Creek I project?

A. With respect to the Energy Vision 2020 Repowering Projects, all facilities are in service except for Dunlap, which will be completed in calendar year 2020. The repowering of

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[9] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Docket No, 17-035-39, Report and Order (May 25, 2018).

the Leaning Juniper wind facility is complete and it was placed in operation in September 2019. The repowering of the Foote Creek I facility is expected to be completed in December 2020. Mr. Hemstreet provides the status of each project in his testimony.

Q. Please describe the New Wind and Transmission Projects.

A. By the end of 2020, the Company will add 1,150 megawatts ("MW") of new wind resources in Wyoming. These resources are three facilities acquired or built by the Company, the 500 MW TB Flats I and II facilities and the 250 MW Ekola Flats project, and one facility that is a combined build-transfer and power purchase agreement, the 400 MW Cedar Springs facility. The Company is also building a new, 140-mile Gateway West transmission segment—the 500 kV Aeolus-to-Bridger/Anticline Transmission Project, plus generation interconnection network upgrades in Wyoming to enable the new wind generation. In Docket No. 17-035-40, the Company requested and received a resource decision for the New Wind and Transmission Projects.[10] In its decision, the Commission approved projected costs for each of the New Wind and Transmission Projects. In this general rate case filing, the Company provides an update on the status of each project, including support for project costs that are above the approved amount, which are prudent and reasonable. Mr. Vail and Mr. Hemstreet provide updates regarding the New Wind and Transmission Projects.

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[10] *Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40 (June 22, 2018).

Q. What is the status of the construction of the New Wind and Transmission Projects?

A. The New Wind and Transmission Projects are scheduled to be in-service in the last quarter of 2020, before the rate effective date in this case. This will ensure that the new wind facilities qualify for PTCs. Mr. Vail and Mr. Hemstreet provide an update regarding the construction status of these projects.

Q. Please describe the other major capital generation project, Pryor Mountain Wind Project.

A. As explained by Mr. Van Engelenhoven, the Pryor Mountain Wind Project will have a nameplate capacity of 240 MW. The facility will be located on a site in Carbon County, Montana, approximately 60 miles south of Billings, Montana. Further, with respect to this project, PacifiCorp and Vitesse, LLC (a wholly-owned subsidiary of Facebook, Inc.) executed an agreement for the purchase of all renewable energy credits ("RECs") generated by the Pryor Mountain Wind Project over a 25-year period under the Company's Oregon Schedule 272 – Renewable Energy Rider Optional Bulk Purchase Option.

Q. Does the Pryor Mountain Wind Project provide quantifiable benefits to customers?

A. Yes. As described in the testimony of Mr. Link, the Pryor Mountain Wind Project produces net customer benefits across a range of price-policy scenarios.

Q. What is the status of the construction of the Pryor Mountain Wind Project?

A. The project is scheduled to be in service in December 2020, before the rate effective date in this case. This will ensure that the project qualifies for PTCs. Mr. Van Engelenhoven provides more information regarding the construction of this project.

Q. How does the Company treat the revenues received from the sales of RECs from the Pryor Mountain Wind Project?

A. Utah's allocation of the revenue from the sale of RECs for this project will be passed back to customers through Electric Service Schedule No. 98 – REC Revenue Balancing Account.

Q. Please describe the updated depreciation rates and decommissioning costs driver in this rate request.

A. On September 11, 2018, the Company filed an application and supporting testimony for an order authorizing a change in depreciation rates effective as of January 1, 2021, which initiated Docket No. 18-035-36 ("2018 Depreciation Study").[11] Around the same time the Company filed similar applications for approval of the 2018 Depreciation Study in Idaho, Oregon, Utah, and Washington. On January 16, 2020, pursuant to the 2020 Protocol, the Company filed an updated decommissioning study in the same states for seven specific resources: Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, and Hayden.[12] On March 17, 2020, the Company filed an updated decommissioning study for Colstrip.[13] On March 19, 2020, in Docket No. 18-035-36, the Company filed a non-unanimous Stipulation on Depreciation Rate Changes that

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[11] *Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, Docket No. 18-035-36.
[12] Docket No. 18-035-36, Supplemental Information, Decommissioning Report (Jan. 16, 2020).
[13] Docket No. 18-035-36, Supplemental Information, Decommissioning Report (Mar. 17, 2020).

proposed changes to certain transmission, distribution and general plant accounts, and modifications including: (1) the removal of Cholla Unit 4 from depreciation rates as of December 2020; and (2) the recognition of the conversion of Naughton Unit 3 to natural gas, with a retirement date of 2029.[14] The stipulating parties also agreed to establish a Phase 2 in that proceeding to address the incremental decommissioning costs in the January and March 2020 supplemental filings and ratemaking treatment for the retired plant associated with the repowered wind facilities. The Commission approved the Stipulation on April 20, 2020.[15]

In this rate request, the Company has incorporated the depreciation rates and study modifications agreed to the Stipulation filed on March 29, 2020. In addition, the Company has reflected incremental decommissioning costs and the repowering retired plant that are subject to Phase 2 of the 2018 Depreciation Study proceeding. Parties in that proceeding agreed that Phase 2 will have a schedule consistent with this general rate case so the Company proposes to incorporate any changes from Phase 2 in the final rates approved in this proceeding. Mr. McDougal's testimony addresses the application of the new depreciation rates to the revenue requirement.

Q. Please explain the Company's overall approach to designing customer rates in this proceeding?

A. The Company continues the Commission's long-established practice of designing rates to be aligned with the cost of service. The proposed allocation of the revenue

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[14] The Stipulating Parties and parties in the Company's depreciation proceedings in Wyoming and Idaho, due to the system wide impacts of depreciation, jointly engaged in numerous and significant good-faith, arms-length negotiations in an effort to resolve the matter. The negotiations resulted in the Stipulation filed in Docket No. 18-035-36 and a comparable stipulation with parties in its Wyoming proceeding and an agreement in principle with the Idaho parties.

[15] Docket No. 18-035-36, Report and Order (Apr. 20, 2020).

requirement and rates reflect the changing conditions since the Company's last rate case six years ago. For rates, the Company makes several rate design updates and various tariff changes to modernize and simplify existing tariffs, including a new monthly credit to customers who choose a paperless billing option. Additionally, the Company is proposing several new pilot rate programs that will provide customers new options to better control their bills based on their ability to shape their usage to take advantage of low-cost periods. The cost of service study, rate spread, rate design, proposed pilots and tariffs are explained in greater detail in Mr. Meredith's testimony. Ms. Nottingham discusses updates to customer service charges and the proposed paperless bill credit.

V. RATE MITIGATION PROPOSALS

Q. What is the purpose of this section of your direct testimony?

A. This section of my testimony discusses the mitigation proposals in this proceeding that minimize the requested rate increase. First, the Company is proposing to reduce rate pressure by using a portion of the remaining TCJA tax deferral balance to buy down the plant balances for the Dave Johnston generating plant and pay off four regulatory assets, with the remaining balance refunded to customers over two years. Second, through implementation of the settlement agreement in Docket No. 17-035-69 (the TCJA proceeding), the Company has used $179.6 million of the available STEP funds to buy-down the undepreciated plant balance of Cholla Unit 4, Craig Unit 1 and a portion of Craig Unit 2. Third, the Company is proposing to extend recovery of the Jim Bridger Units 1 and 2 beyond the depreciation lives in the 2018 Depreciation Study for recovery through a regulatory asset. Altogether these mitigation measures reduce the revenue requirement increase by $66.1 million.

Q. What is the TCJA?

A. The TCJA was enacted in December 2017 and lowered the federal income tax rate from 35 percent to 21 percent. The Commission directed the Company to record the difference between the federal income tax liability under the law in effect on December 31, 2017, and the law in effect on and after January 1, 2018, to a deferred regulatory account.[16]

Q. Have the Company's customers already received benefits of the TCJA?

A. Yes. The Company's Utah customers have already experienced a sizable decrease in rates through its pass-through of the change in the corporate income tax rate established by the TCJA.[17] Initially, the Commission approved an ongoing, annual rate reduction of $61 million to be allocated to retail customers and Special Contract customers 1 and 2, effective May 1, 2018. Subsequently, in a final report to the Commission, the Company provided an overview of the TCJA, a final calculation of the full revenue requirement impacts of the TCJA and the effects related to the excess deferred income tax ("EDIT"), and set forth a proposal for returning ongoing and additional TCJA benefits to customers and to recover offsets to the deferred amounts. Following the Company's supplemental filing, the Commission approved an unopposed Settlement Stipulation ("TCJA Settlement") agreeing to: (1) an annual rate reduction of $61 million associated with the annual current income tax savings from the TCJA; (2) defer

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[16] Docket No. 17-035-69, Order Granting Motion for Deferred Accounting Order and Notice of Scheduling Conference at 3 (Feb. 28, 2018).
[17] *Id.*, Order (Apr. 27, 2018).

$4.9 million per year of the remaining current income tax savings in a regulatory liability associated with the TJCA until the effective date of the rates set in this proceeding; (3) defer non-protected EDIT balances toward accelerated depreciation of the Dave Johnston generating plant; and (4) defer property-related EDIT balance amortizations with ratemaking treatment to be determined in the Company's next filed rate case, which is this proceeding.[18]

Q. What is the remaining balance of the TCJA deferred regulatory account?

A. The remaining balance of the TCJA deferred regulatory liability is approximately $144.0 million, details of which are discussed in the testimonies of Ms. Kobliha and Mr. McDougal.

Q. How is the Company proposing to use the remaining TCJA deferred balance in this proceeding?

A. The Company is proposing to apply the majority of the balance, approximately $77.5 million to depreciate, or buy-down, Utah's allocation of the plant balance of a generation plant and pay off certain regulatory assets. The remaining TCJA balance, estimated to be $66.5 million, will be passed back to customers through Schedule 197 over two years. Consistent with the TCJA Settlement, the Company is proposing to apply the incremental non-protected EDIT funds to depreciate the plant balance of the Dave Johnston generating plant. In addition, it is proposing to pay off the regulatory assets associated with the 2017 Protocol, EIM benefits, Deer Creek mine, and the closure of the Carbon generating plant. This treatment benefits customers by reducing the revenue requirement both in this case and in the longer term by eliminating a

[18] *Id.*, Order Approving Settlement Stipulation (Nov. 9, 2018).

significant portion of the known customer cost obligations for the plant and regulatory assets. As discussed by Mr. McDougal, buying down these balances reduces the revenue requirement increase by $21.3 million per year.

Q. Please explain the Company's proposal to return the remaining $66.5 million in deferred tax savings to customers.

A. The Company proposes to refund the balance of the deferred tax savings to customers through Schedule 197, Federal Tax Act Adjustment over the next two years. Providing an on-going bill credit will help offset the impact of the increase in the revenue requirement. The Company proposes a phase-down approach with $44.3 million to be refunded beginning January 1, 2021, and the remaining $22.2 million to be refunded beginning January 1, 2022. This will allow for a gradual phase-in of the proposed revenue requirement increase, resulting in a net increase of 2.6 percent January 1, 2021, 1.1 percent January 1, 2022, and 1.1 percent January 1, 2023. Mr. Meredith provides this calculation in his testimony.

Q. Does buying-down the plant for Dave Johnston have any impact on the Company's on-going operation of the plant?

A. No. The Company will continue to operate the plant for customers as long as it is economic to do so.

Q. Please explain the Company's second rate mitigation proposal—using the STEP balance to buy-down the plant balances of Cholla Unit 4 and Craig Units 1 and 2.

A. The Company is proposing to use the current balance in the STEP regulatory liability account, which is $179.6 million, to pay down the undepreciated plant balance of Cholla Unit 4 and Craig Units 1 and 2. In approving the TCJA Settlement, the

Commission approved the use of the STEP regulatory account to buy down Utah's share of the undepreciated plant balances of certain generating plants, including Cholla and Craig Units 1 and 2.

Q. Why is the Company proposing to buy down the balance for Cholla Unit 4 at this time?

A. As discussed later in my testimony, and more specifically by Mr. Link, the Company has determined that it is economic to close Cholla Unit 4 at the end of 2020. Once a unit closes, the Company would need to seek recovery of unrecovered investment, as well as closure and incremental decommissioning costs, through a regulatory asset. In lieu of recovering the approximate $145.9 million in remaining plant balance and estimated decommissioning cost through a regulatory asset, the Company is proposing to implement the TCJA Settlement, wherein parties agreed to the order in which STEP funds would be applied to retiring coal plants. If STEP funds are not used to buy down this balance, the Customer's revenue requirement need in this case would increase by approximately $33.7 million.[19]

Q. Why is the Company proposing to buy down the balance for Craig Units 1 and 2 at this time?

A. Unlike Cholla Unit 4, Craig Units 1 and 2 are expected to continue operating for several more years—through 2025 and 2026, based on the economic analysis in the Company's 2019 Integrated Resource Plan ("2019 IRP").[20] Depreciation rates are designed to recover costs through that period. The TCJA settlement set the order of plants the STEP

[19] This assumes recovery of the balance through April 2025, which was the proposed depreciation life in the 2018 Depreciation Study, in Docket No. 18-035-36.
[20] *PacifiCorp's 2019 Integrated Resource Plan,* Docket No. 19-035-02.

dollars were to be used for, with Cholla being first, followed by Craig Units 1 and 2. The remaining amount of STEP funds after accounting for Cholla Unit 4 are $33.7 million. Consistent with the settlement, the Company proposes to buy down the Utah-allocated plant balance for Craig Unit 1 and a portion of Craig Unit 2 at this time with the remaining available STEP funds to decrease the revenue requirement need in this case by approximately $6.1 million. Buying down the plant balances for these units facing a more near-term retirement provides greater near-term value to customers than applying the same amount of funds to buy-down units in facilities that will have overall longer lives.

Q. Does buying-down the plant for Craig Units 1 and 2 have any impact on the Company's on-going operation of the units?

A. No. The Company will continue to operate the units for customers as long as it is economic to do so.

Q. Please explain the Company's third rate mitigation proposal—creating regulatory asset accounts to recover the plant balances of the Jim Bridger Units 1 and 2 through 2037.

A. The Company proposes to extend the cost recovery period of the plant balances for these units beyond the depreciation life to reduce near-term rate pressure.

In the Company's approved depreciation rates, the lives for Jim Bridger Units 1 and 2 are accelerated from 2037 to 2028 and 2032, respectively. The Company's 2019 IRP shows the units are economic to operate until 2023 for Unit 1 and 2028 for Unit 2. However, the assumed lives for Units 3 and 4 at the Jim Bridger plant remain unchanged at 2037. Since half of the units at the plant are expected to continue to operate until 2037, it is reasonable to extend recovery of the costs through the remaining operating life of the plant consistent with the prior depreciation study treatment. This also reduces near-term rate pressure and allows time for the STEP balance to accumulate additional funds that can be used to buy-down the plant balances at the time they are retired, which, based on the 2019 IRP, is expected to be sooner than reflected in the 2018 Depreciation Study. This proposed extension of cost recovery beyond the units' depreciable lives reduces the revenue requirement increase by approximately $5.0 million, as identified in the direct testimony of Mr. McDougal.

VI. CLOSURE OF CHOLLA UNIT 4

Q. Please describe Cholla Unit 4 and the Company's decision to retire the unit.

A. On December 27, 2019, the Company announced it would retire Cholla Unit 4 by December 31, 2020. The Cholla power plant consists of four units located near Joseph City, Arizona, with a combined generating capability of 995 MW. The Company owns approximately 37 percent of the plant's common facilities and 100 percent of Unit 4, which was commissioned in 1981 with a generating capability of 395 MW. Based on an economic analysis discussed by Mr. Link, the Company initiated the process of retiring Unit 4 and anticipates being able to achieve retirement by year-end 2020.

Q. Is the Company requesting a deferral account associated with the closing costs related to the retirement of Cholla Unit 4?

A. Yes. While the Company, as I described above, uses the balance in the STEP regulatory liability account to buy-down the remaining Utah-allocated, plant balance and decommissioning costs,[21] other costs associated with closing the unit remain. These costs relate to Construction Work in Progress ("CWIP"), material and supplies, and liquidated damages. As discussed by Mr. McDougal, the Company proposes to defer and amortize these costs through April 2025, which is the depreciable life of Cholla as originally proposed in the depreciation study filed in Docket No. 18-035-36.[22] The Company's proposal to defer and amortize the costs related to CWIP, material and supplies, and liquidated damages through April 2025 is reasonable as it extends the recovery of these costs over the remaining life of Cholla Unit 4 prior to the Company's decision to discontinue operations of the unit. The Company also anticipates using the regulatory asset account to true-up any differences in final closing costs and decommissioning costs from the estimates reflected in this case.

VII. SUBSCRIBER SOLAR PROGRAM

Q. What is the purpose of this section of your direct testimony?

A. As explained by Mr. Hoogeveen, the Company offers a number of customer renewable resource options, including its Subscriber Solar Program. In this section of my testimony, I provide an overview of the Company proposed expansion of the program.

Q. Please explain the Company's Subscriber Solar Program.

A. The Company's Subscriber Solar Program, which was approved in Docket No. 15-035-61,[23] allows customers to subscribe to cover part or all of their electric energy use from

[21] *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018"*, Docket No. 17-035-69, Order Approving Settlement Stipulation (Nov. 9, 2018).
[22] *See Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021*, Docket No. 18-035-36, Application filed Sept. 11, 2018.
[23] *In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program,* Docket No. 15-035-61, Tariff Approval Letter dated Nov. 13, 2015.

a solar power resource. The solar energy is from a 20 MW solar plant in Millard County, Utah. The program provides customers with the ability to use solar even if they cannot afford solar panels or do not want solar panels on their home. The program allows for customers to subscribe to either blocks of 200 kWh or to 100 percent of their total usage. Customers on the current program pay a fixed solar generation charge and a delivery charge in lieu of their regular retail rates.

Q. Is the Subscriber Solar Program fully subscribed?

A. Yes. It has been a popular program and the Company has received a lot of customer interest in it. Even though blocks occasionally become available from time to time, the Program has been fully subscribed since 2017 and there is currently a wait list of customers who have requested to participate. Currently, there are over 2,900 customers enrolled in the program, which includes approximately 2,300 residential customers. Therefore, the Company is proposing to expand the program under a new design, which will create opportunities for new subscribers to join the program.

Q. Please describe the Company's proposed expansion of the Subscriber Solar Program.

A. The Company is proposing a new design of the current Subscriber Solar Program that will not only increase opportunities for new subscribers to join but will also make the program more understandable to customers. The redesigned program will be available to residential, small non-residential, and large non-residential customers through Electric Service Schedule No. 73, Subscriber Solar Program Rider - Optional. The proposed redesign continues to provide customers the option of participating in a utility scale solar photovoltaic resource(s) to be acquired by the Company at levels equal to100 percent of energy usage or in 200 kWh blocks. For the new program, however, the participants will pay a renewable premium charge for the subscribed energy in addition to their regular retail rates, rather than program rates in lieu of their regular rates. The renewable premium is calculated as the difference between the resource cost and avoided costs. In addition, the Company is proposing contract terms that vary depending on whether the customer subscription amount is anticipated to be above or below 100 MWh per month. For larger customers the contract will allow the Company to pass administrative and marketing savings onto the subscriber customers through a discount. Please see the testimony of Mr. Comeau for the details of the enhancements to the Subscriber Solar Program.

VIII. PROPOSED WILDLAND FIRE COST RECOVERY MECHANISM

Q. What is the purpose of this section of your direct testimony?

A. The purpose of this section of my testimony is to provide an overview of the proposed cost recovery mechanism for wildland fire mitigation costs.

Q. Why is the Company proposing a Wildland Fire Mitigation Balancing Account?

A. The Utah legislature recently enacted HB 66[24] which requires qualified utilities to file a wildland fire protection plan with the Commission every three years, with the first plan filed by June 1, 2020. HB 66 also provides for timely cost recovery of prudent capital investment and expenses. Mr. Mansfield discusses the Company's current wildfire mitigation efforts. As explained by Mr. Mansfield, the Company is preparing its June 1, 2020 Wildland Fire Protection Plan.

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[24] HB 66, signed by Governor Herbert Mar. 28, 2020. *See* https://le.utah.gov/~2020/bills/static/HB0066.html.

Q. Please describe the Company's proposed Wildland Fire Mitigation Balancing Account.

A. HB 66 provides for the deferral and collection of prudent capital investment costs and expenses to implement the Wildland Fire Protection Pan that is not included in the Company's rates. Under its proposed mechanism, the Company is establishing a base amount of capital costs and operations and maintenance ("O&M") expenses related to the Wildland Fire Mitigation Plan and will compute the incremental revenue requirement, which allows for a Commission prudency review of capital costs and expenses in future rate proceedings. Because its first Wildland Fire Protection Plan is not due until June 1, 2020, the Company's revenue requirement in this rate case includes forecasted capital additions and O&M expenses related to the plan, which it proposes to establish as the base amount for the for the Wildland Fire Mitigation Balancing Account. The Company will update these amounts in rebuttal testimony at which point its Wildland Fire Protection Plan would have been filed. Mr. McDougal discusses the details of the Wildland Fire Mitigation Balancing Account in his testimony.

IX. RECOMMENDATION

Q. Please summarize the Company's recommendation.

A. I recommend the Commission approve the Company's requested rate increase of approximately $95.8 million and the proposed use of the Schedule 197 credit to provide for a phase-in of the revenue requirement increase, along with the other proposed rate mitigation measures, proposed updates and changes to customer rate designs, and the other recommendations included within the Company's Application and supporting witness testimony.

Q. Does this conclude your direct testimony?

A. Yes.