BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-21-07**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS	)	**Direct Testimony of Joelle R. Steward**
RATES AND CHARGES IN IDAHO	)	**REDACTED**
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

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ATTACHED EXHIBIT

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 general rate case 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 filed general rate case in 2011 ("2011 Rate Case")[1] and the stipulated agreement approved in lieu of a rate case in 2013 ("2013 Stipulation Agreement").[2] This rate case filing reflects the Company's prudent and efficient management of its costs that has allowed it to not request an increase in base rates for eight 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 a significant increase in benefits from low-cost new and repowered wind resources that lower net power costs ("NPC"), along with the production tax credits ("PTCs"), incorporation of the tax savings associated with federal Tax Cut and Jobs Act ("TCJA"),[3] new transmission investments to support and strengthen the bulk power system, and a modernization of rate designs to provide better price signals.

The requested revenue requirement increase in this general rate case filing is $19.0 million, or approximately 7.0 percent. The Company has reflected a rate mitigation measure to use approximately $3.3 million of the TCJA tax deferred balance to buy down certain regulatory asset balances, which reduced the requested increase by $1.1 million. With respect to the remaining $8.5 million of TCJA deferred tax balance, the Company has not reflected a refund of this balance in the initial filing given the

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[1] *In the Matter of the Application of PacifiCorp, DBA Rocky Mountain Power, for Approval of Changes to Its Electric Service Schedules*, Case No. PAC-E-11-12, Order No.32432, approving the Settlement Stipulation with one condition (Jan. 10, 2012).
[2] *In the Matter of the Application of PacifiCorp, DBA Rocky Mountain Power, to Initiate Discussions with Interested Parties on Alternative Rate Plan Proposals,* Case No. PAC-E-13-04, Order No. 32910 (Oct. 24, 2013).
[3] I refer to the tax savings associated with the reduction of the federal corporate tax rate as the "TCJA deferred tax benefits."

potential of an increase in the federal corporate income tax rate. However, if an increase in the corporate tax rate is not enacted this year, which would offset some of the deferred TCJA savings, then the Company proposes to refund the remaining balance over two years.

I also want to acknowledge the willingness and support of the Idaho Public Utilities Commission ("Commission"), its staff and the Idaho stakeholders to consider and adopt innovative and non-traditional ratemaking treatment through the years that have enabled the Company to stay out of a general rate case for 10 years. I describe many of these efforts through the background provided in my testimony for various cost elements. The Company appreciates this open engagement by Idaho parties to continually find ways to balance the interests of all parties in creative ways.

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 Company's proposed treatment of the remaining TCJA tax deferred balance. Section VI discusses the Company's proposals regarding the interruptible products provided by P4 Productions, also known by the name of its parent company, Bayer, (formerly, Monsanto) to the Company.

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

A. I recommend that the Commission:

- Authorize rates to recover an overall Idaho revenue requirement of $290.5 million, which is an increase of $19.0 million, or 7.0 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 using approximately $3.3 million of TCJA deferred tax benefits to buy down the decommissioning and closure costs for Cholla Unit 4 and other regulatory asset balances, described in my testimony, to remove those costs from rates and mitigate the rate increase.
- Approve as prudent the Company's request to include the incremental additions to the Company's rate base, including the full costs for the new wind, transmission and wind repowering projects that were part of the Company's Energy Vision 2020 filings, the repowering of 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 natural gas, numerous bulk transmission system projects, and the Lake Side 2 natural gas generating plant for a total 2021 Idaho rate base of approximately $1.0 billion, as discussed in the testimony of various witnesses in this rate case.
- Approve an overall cost of capital of 7.63 percent, which is comprised of a capital structure of 52.83 percent equity, 47.16 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 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, subject to any alternative agreement on value negotiated between the Company and Bayer during the pendency of this case, the Company's proposal

- regarding the valuation of the interruptible products provided by P4 Productions and the related credit as described in the testimony of Mr. Craig M. Eller.
- Approve the innovative and equitable cost of service, rate spread and rate design proposals, set forth in the testimony of Mr. Robert M. Meredith.

III. PREVIOUS RATE CASE HISTORY

Q. Please discuss the Company's most recent rate changes.

A. The Company's efficient management of costs and the Commission's approval of alternative ratemaking treatment has allowed the Company to avoid filing a general rate case for 10 years. On May 27, 2011, the Company filed its 2011 Rate Case requesting an increase in revenues from Idaho operations for an overall price change of 15.0 percent or $32.7 million. The Commission approved a comprehensive, multi-year, settlement stipulation, authorizing a two-step rate increase of $17.0 million effective January 10, 2012, and a rate increase of $17.0 million effective January 1, 2013.[4] As part of the 2011 Rate Case Settlement, the Company agreed to not file a rate case before May 31, 2013. On March 1, 2013, the Company filed an application to initiate discussions with interested parties on alternative rate plan proposals and a notice of intent to file a rate case.[5] Following meetings among the parties, the Company filed the 2013 Stipulation Settlement Agreement, which the Commission approved on October 24, 2013. The 2013 Stipulation Settlement Agreement provided for the base

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[4] *In the Matter of the Application of PacifiCorp, DBA Rocky Mountain Power, for Approval of Changes to Its Electric Service Schedules,* Case No. PAC-E-11-12, Order No. 32432 (Jan. 10, 2012), approving Settlement Stipulation with one condition.

[5] *In the Matter of the Application of PacifiCorp, DBA Rocky Mountain Power, to Initiate Discussions with Interested Parties on Alternative Rate Plan Proposals,* Case No. PAC-E-13-04, Order No. 32910 (Oct. 24, 2013).

revenue requirement for all customer schedules to increase by a uniform percentage of 0.77 percent in the energy rate of each schedule. That increase was effective January 1, 2014.

Over the course of the last eight years, rates were decreased as a result of two proceedings which allowed the Company to avoid filing a rate case. First, in 2016, the Commission granted the Company's requested rate decrease, which included a base rate reduction and updated NPC for base rates and the energy cost adjustment mechanism ("ECAM").[6] Second, in 2018, the Commission approved a settlement stipulation, which provided decreases to retail revenues and the ECAM rate to reflect the TCJA deferred tax benefits.[7]

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. The Company is proposing a test period based on calendar year 2020 with known and measurable changes through the 12 months ending December 31, 2021. The use of this test period is necessary to incorporate the updated depreciation study, which went into effect January 1, 2021, and other capital additions that go into service through 2021.

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[6] *In the Matter of the Application of PacifiCorp dba Rocky Mountain Power to Update Base Net Power Costs and Implement a Rate Stability Plan, Case No. PAC-E-16-12,* Order No. 33668 (Dec. 14, 2016).
[7] In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking, Case No. GNR-U-18-01, Order No. 34072 (June 1, 2018) and Order No. 34331 (May 3, 2019).

The costs for the new investments are partially offset by PTCs and the significant increase in zero-fuel-cost energy. The testimony of Mr. Steven R. McDougal discusses the development of the test period.

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 7.63 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 52.83 percent equity, 47.16 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 Idaho-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").[8] The Commission approved the Company's application on April 22, 2020, finding that the methodology fairly and reasonably allocates the Company's system costs and, as such, is within the public interest.[9] 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 similar to 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

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[8] *In the Matter of Rocky Mountain Power's Application for Approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol,* Case No. PAC-E-19-20.
[9] *Id.* Order No. 34649 (Apr. 22, 2020).

updated depreciation rates. I discuss each of these drivers in more detail below.

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

A. The filing reflects a number of capital investments made 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) the Foote Creek I repowering project; 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, the Lake Side 2 natural gas generating plant, and various transmission projects. These capital investments are more fully discussed in the testimonies of Mr. Rick T. Link, Mr. Robert Van Engelenhoven, Mr. Timothy J. Hemstreet, Mr. James C. Owen, and Mr. Richard A. Vail.

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")[10]; 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 the Company'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 2021, the Company is able to renew

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[10] "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, Goodnoe Hills, and Leaning Juniper.

the federal PTCs on all repowered wind facilities for another 10 years. The Commission approved the Company's Repowering Projects in Case No. PAC-E-17-06 as prudent and in the public interest and allowed the Company to track the annual investment and operating costs and benefits of the Repowering Projects using the Resource Tracking Mechanism ("RTM"), which is included as a component of the Company's ECAM.[11] I discuss the Company's proposal regarding the RTM later in my testimony. For further details regarding the Repowering Projects, see Mr. Hemstreet's testimony.

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

A. Yes. The Company is seeking approval for the costs to repower the Company-owned wind facility—Foote Creek I. As described in the testimony of Mr. Hemstreet and Mr. Link, the Foote Creek I project produces net customer benefits across a range of price-policy scenarios. The upgrade to repower Foote Creek I is prudent and reasonable and in the public interest. With respect to repowering the Foote Creek I wind facility, Mr. Hemstreet provides project details in his testimony and Mr. Link provides the economic analysis of the project in his testimony.

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

A. With respect to the Energy Vision 2020 Repowering Projects, all facilities are in service. The repowered Foote Creek I facility was placed in-service on March 24, 2021.

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[11] *In the Matter of the Application of Rocky Mountain Power for Binding Ratemaking Treatment for Wind Repowering,* Case No. PAC-E-17-06, Order No. 33954 at 7 (Dec. 28, 2017). As part of the Stipulation, despite the Commission's finding in Order No. 33954, a party to the Stipulation may challenge the prudence of actual costs and benefits incurred in implementing the wind repowering project when the Company seeks recovery of those costs in a later proceeding.

Mr. Hemstreet provides the status of each project in his testimony.

Q. Please describe the New Wind and Transmission Projects.

A. The Company is adding 1,150 megawatts ("MW") of new wind resources in Wyoming, with 854 MW online by the end of 2020. These resources include three facilities acquired or built by the Company, the 500 MW TB Flats I and II facilities, 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 has also built 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 Case No. PAC-E-17-07, the Company requested and received a Certificate of Public Convenience and Necessity for the New Wind and Transmission Projects.[12] In its decision, the Commission approved an overall hard cap of projected costs for the New Wind and Transmission Projects. Similar to the Repowering Projects, the Company is tracking the annual investment and operating costs and benefits of the New Wind and Transmission Projects using the RTM. I will address the Company's proposal to terminate the RTM once the new resources are reflected in base rates in this proceeding. Further, the Company provides an update on the status of each project, including support for prudent and reasonable project costs that exceed the approved amount. Mr. Vail and Mr. Hemstreet provide updates regarding the New Wind and Transmission Projects.

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[12] *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for New Wind and Transmission Facilities*, Case No. PAC-E-17-07, Order No. 34104, approving a Stipulation Agreement with one condition (July 20, 2018); Order No. 34139, order on reconsideration (Sept. 6, 2018).

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

A. Ekola Flats and Cedar Springs facilities were placed in-service on December 31, 2020, and December 8, 2020, respectively. To maximize customer benefits TB Flats is being placed in-service in a phased approach. The first phase was completed on December 31, 2020, and as additional sections are completed, they are being placed in-service. TB Flats is expected to be completed by July 2021 ensuring that all the new wind facilities qualify for PTCs. Mr. Vail and Mr. Hemstreet provide an update regarding the construction status of these projects.

Q. Are the Company's forecasted costs for the New Wind and Transmission Projects currently expected to exceed the overall cap set by the Commission in Case No. PAC-E-17-07?

A. Yes. The Commission's Order No. 34104 in Case No, PAC-E-17-07 set a cap of $[redacted] million for the New Wind and Transmission Projects. The current forecasted costs for the New Wind and Transmission Projects are in Confidential Exhibit No. 2. The Company's current estimate of the New Wind and Transmission Projects is approximately $[redacted] million or 2.2 percent over the cap approved by the Commission. This overall increase is attributable to increases in the 230 kV Network Upgrades, Ekola Flats wind facility, and TB Flats wind facility, which are offset, in part, by a decrease in the Cedar Springs II wind facility. Mr. Vail and Mr. Hemstreet address the drivers of the increases for these projects.

Q. How did the total cost of the Energy Vision 2020 project compare to the Company's forecast?

A. The Company's total projected cost for the Repowering Project, New Wind, and Transmission Projects was $[redacted] million. The total cost of these projects included in the case is $[redacted] million or 0.83 percent less than projected.

Q. Should the Commission approve the recovery on and of the total costs for the New Wind and Transmission Projects, including the amounts that exceed the cost cap set by the Commission in Case No. PAC-E-17-07?

A. Yes. Despite obstacles that were beyond the Company's control, a primary one being increased costs due to the COVID-19 pandemic, the Company was able to deliver the Energy Vision 2020 project under budget increasing the overall benefits to customers. In finding that a cap is warranted, the Commission stated that "the Company controlled the cost estimates and contingencies that the Commission relied on to impose the cap."[13] However, the Company could not have predicted the circumstances that have led to the increase in costs; as such, the cost increases were beyond the Company's control but do not compromise the overall economic benefits to customers for the projects. The increase related to the 230 kV Network Upgrades is attributable to market conditions that changed after the original estimate was prepared in 2018 due to an increase in projects in the industry. These market conditions caused upward pressure on costs associated with linemen resources and materials, including steel. The increases related to TB Flat I and II and Ekola Flats wind facilities are due to the Company's vendor for the wind turbine generators being unable to hold pricing because of steel

[13] Order No. 34139 at 3.

price risk, tariff on Chinese goods, and transportation costs. As discussed by Mr. Vail and Mr. Hemstreet, the Company attempted to mitigate these increases but could not eliminate them.

In Order No. 34139, the Commission stated that the Company's main rational for building the New Wind and Transmission Projects was economic rather than an immediate need for reliability or safety.[14] I respectfully disagree. As explained further by Mr. Link, beginning in 2017, the Company's IRP has demonstrated a need for new wind resources. Additionally, even with these increases, the New Wind and Transmission Projects are still an overall benefit to the Company's customers. Furthermore, the Company should not be punished for seeking review and approval before undertaking a significant investment on behalf of customers. As a result, the Company requests recovery on and of the total cost of the New Wind and Transmission Projects, including those costs that exceed the cost cap, as they were prudently incurred and reasonable in amount.

Q. What is the Company's proposal regarding the RTM that is currently tracking the costs and benefits associated with the Repowering Projects and New Wind and Transmission Projects?

A. The RTM is a nontraditional ratemaking approach that allowed the Company, in between rate cases, to properly match the timing of the benefits and costs for the Repowering Projects and New Wind and Transmission Projects. The RTM aligned the costs and benefits so that customers received the full benefits from capital-intensive projects while the Company received appropriate cost recovery of the prudent

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[14] *Id.*

investment. With respect to the Repowering Projects and New Wind and Transmission Projects, the respective RTMs served their purpose of matching the return of benefits of the projects to customers and allowing appropriate cost recovery. Therefore, it is appropriate to move these investments into the Company's rate base and incorporate them into the Company's rates in this rate case proceeding, consistent with the treatment of all other capital investments. The Company proposed the RTM as a short-term solution to avoid the need of back-to-back rate cases to incorporate these investments in rates. Mr. McDougal addresses the addition of these investments in rate base in his testimony.

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 has a nameplate capacity of 240 MW. The facility is 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 Pryor Mountain Wind Project was placed in-service on April 1, 2021, before the rate effective date in this case. Mr. Van Engelenhoven provides more information regarding the construction of this project.

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

A. An estimate of Idaho's allocation of the revenue from the sale of RECs for this project is included in Mr. McDougal's revenue requirement calculation, reducing costs for Idaho customers. Actual REC revenues are compared to the base amount established in this case annually and the difference is tracked in the ECAM, consistent with treatment for all REC revenues. Mr. McDougal describes this in his testimony.

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 Case No. PAC-E-18-08 ("2018 Depreciation Study").[15] Around the same time the Company filed similar applications for approval of the 2018 Depreciation Study in Wyoming, Oregon, Utah, and Washington. In January 2020, pursuant to the 2020 Protocol, the Company completed an updated decommissioning study for seven coal-fired resources: Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, and Hayden. In March 2020, the Company completed an updated

[15] *In the Matter of the Application of Rocky Mountain Power for Authorization to Change Depreciation Rates Applicable to Electric Property*, Case No. PAC-E-18-08.

decommissioning study for Colstrip.[16] The parties in the Company's depreciation proceedings in Idaho, Utah, and Wyoming, due to the consistency of depreciation rates, jointly engaged in numerous and significant good-faith, arms-length negotiations in an effort to resolve the matter. On May 21, 2020, the Company and Idaho parties finalized an agreement in principle.[17] On June 15, 2020, the Company filed a Stipulation for Phase I, new depreciation rates, and requested that the Commission establish Phase II to facilitate additional discussion on the treatment of the incremental costs identified in the 2020 decommissioning studies.[18] On August 18, 2020, the Commission approved the depreciation rates as filed in the Stipulation and authorized Phase II.[19]

On October 8, 2020, after negotiating with parties, the Company filed the Phase II Stipulation that resolved treatment of the incremental decommissioning costs from the 2020 decommissioning studies. On December 11, 2020, the Commission approved the Phase II Stipulation as filed.

In this application, the Company has incorporated the depreciation rates and incremental decommissioning costs approved by the Commission. Mr. McDougal's testimony addresses the inclusion of the new depreciation rates and incremental decommissioning costs into the revenue requirement calculation.

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[16] The March 2020 decommission study for Colstrip was filed in Case No. PAC-E-18-08, Confidential Colstrip Decommissioning Report (Mar. 16, 2020).

[17] In Utah and Wyoming, the negotiations among the parties resulted in a stipulation agreement filed in Docket No. 18-035-36 in Utah and a comparable stipulation agreement with parties in its Wyoming proceeding in Docket No. 20000-539-EA-18 (Record No. 15095).

[18] Case No. PAC-E-18-08, Stipulation on Depreciation Rate Changes (June 15, 2020).

[19] Case No. PAC-E-18-08, Order No. 34754 (Aug. 18, 2020).

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 requirement and rates reflect the changing conditions since the Company's last filed rate case 10 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 and updates to the valuation and credit for interruptible products received from Bayer. The cost of service study, rate spread, rate design, 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. Mr. Eller explains the valuation and related credit for the interruptible products received from Bayer.

V. PROPOSAL FOR DEFERRED TCJA BENEFITS

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

A. This section of my testimony discusses the Company's proposals for using the remaining TCJA deferred tax benefits balance. First, the Company proposes to buy down regulatory asset balances, including the decommissioning and closure costs for Cholla Unit 4, which reduces the Company's revenue requirement in this case by approximately $1.1 million by eliminating these costs from rates. Second, after the buy down of the regulatory asset balances, approximately $8.5 million of the TCJA deferred tax balance remains. The Company has not reflected treatment in rates for the remaining balance at this time given the potential of an increase in the corporate income tax rate that is being considered in the U.S. Congress during the pendency of this proceeding. However, if an increase in the corporate income tax rate is not enacted this year, the Company proposes to refund the remaining TCJA deferred tax balance over two years, beginning January 1, 2022. The Company will provide an update to the treatment of the remaining TCJA tax deferred balance in rebuttal testimony.

Q. What is the TCJA?

A. After the TCJA was enacted in December 2017 and lowered the federal income tax rate from 35 percent to 21 percent, the Commission opened a multi-utility case to investigate whether to adjust the rates of certain utilities as a result of the reduced tax rate.[20] The Commission directed utilities to account for the tax benefits as a regulatory liability and report on how they were impacted and how benefits could be passed through to customers.[21] The Company filed its report on March 30, 2018, in Case No. GNR-U-18-01.

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

A. Yes. The Company's Idaho 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.[22] Initially, the Commission approved a settlement stipulation dated May 10, 2018, that provided (1) a decrease of Idaho retail revenues by $8.385 million or approximately 3.0 percent, which consisted of $6.185 million in federal and state income tax savings returned to customers through Electric Service Schedule No. 197,

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[20] In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking, Case No. GNR-U-18-01, Order No. 33965 (Jan. 17, 2018).
[21] Id.
[22] Case No. GNR-U-18-01, Order Nos. 34072 and 34331.

and $2.2 million reduction to Electric Service Schedule No. 94, Energy Cost Adjustment rate; (2) an offset of $3.5 million of the ECAM 2013 regulatory asset balance, which decreased the annual ECAM rate by $2.2 million; and (3) that any under- or over-collection of the tax benefits would be recorded as a regulatory asset and deferred until base rates are set through a general rate case.[23] As part of this settlement stipulation, the Company agreed to file a final report of the Company's net savings due to the federal tax law change on June 15, 2018, which initiated a Phase II of the proceeding that reviewed the remaining deferred balances and addressed ratemaking treatment for them.

In Phase II, a second settlement stipulation dated March 5, 2019, was approved by the Commission.[24] The March 5 settlement stipulation provided for in part: (1) an increase to Schedule 197 rates of $1.4 million, thus refunding to Idaho retail customers approximately $7.6 million annually; (2) amortize over two years the deferred current tax savings balance of approximately $1.1 million through the ECAM; (3) as the Excess Deferred Income Taxes ("EDIT") resulting from the tax law change amortize in rates, the inclusion of a rate base carrying charge offset to account for the corresponding increase in rate base associated with amortized EDIT until the Company's next general rate case; (4) a reduction of the actual annual average rate assumption method ("ARAM") amortization of protected property-related EDIT, and the annual straight-line amortization of non-protected property and non-property EDIT, by a rate base

[23] Case No. GNR-U-18-01, Order No. 34072. Also, per the TCJA Settlement, the final Schedule 94 ECAM rate collected $1.8 million more than originally approved to continue offsetting the $1.8 million incremental depreciation deferral.
[24] Case No. GNR-U-18-01, Order No. 34331 (May 3, 2019).

offset calculated at the pre-tax weighted average cost of capital on the after-tax EDIT amounts until the EDIT rate base balances are updated and included in the next general rate; and (5) until the next general rate case, refund through the ECAM the actual annual ARAM amortization of protected property EDIT, less the associated rate base offset. The non-protected property and non-property EDIT would be amortized over seven years and be used in part to offset the 2013 incremental depreciation expense deferral approved by Commission in Order No. 32910.[25]

Q. Were there further changes to the TCJA settlements that modified treatment of the TCJA benefits?

A. Yes. On March 26, 2020, the Company filed a Notice of Intent to file a General Rate Case with the Commission. However, as the time to file the case got closer, recognizing the impact that the COVID-19 pandemic was having on its customers and knowing a rate increase at that time in particular would be challenging, the Company initiated discussions with Commission Staff and other Idaho stakeholders to develop a rate plan that would allow it to delay filing a general rate case.

The Company was able to reach an agreement with Commission Staff, Bayer, the Idaho Conservation League, the Idaho Irrigation Pumper Association, and PacifiCorp Idaho Industrial Customers to delay the general rate case so no change to general rates would be effective prior to January 1, 2022. With the delay in the rate case, the parties agreed, among other things, to (1) support a one-year deferral of the incremental annual depreciation expense approved to Case No. PAC-E-18-08, and (2) that the Company could file an accounting application to seek approval for

[25] Id.

modifications to the Phase II tax settlement stipulation in Case No. GNR-U-18-01, on the ratemaking treatment for the TCJA. On July 2, 2020, the Company filed the accounting application in Case No. PAC-E-20-03. The accounting application requested approval to use the tax benefits to buy-down the net plant balance of Cholla Unit 4, which was to be removed from service in December 2020, and to cease the refund of the tax savings in the ECAM filing in 2021 in order to use any remaining savings to mitigate the rate impact in the 2021 general rate case filing. The Commission approved the accounting application on December 31, 2020.[26] The modification allowed the Company to use a portion of the remaining balance from excess deferred income tax savings from the TCJA to buy-down the remaining plant balance from Cholla Unit 4 and offset future rate increases.

Q. How much of the TCJA deferred balance was used to buy down the Cholla Unit 4 plant balance?

A. As explained in Mr. McDougal's testimony, of the remaining $28.2 million of TCJA savings available for refund, the Company applied approximately $16.4 million to buy-down Idaho's allocation of investment in Cholla Unit 4, which reduced the revenue requirement in this case by approximately $5.5 million.

Q. After the buy down of the Cholla Unit 4 plant balance, what is the remaining balance of the TCJA deferred regulatory account?

A. The remaining balance of the TCJA deferred regulatory liability is approximately $11.8 million, details of which are discussed in the testimony of Mr. McDougal.

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[26] In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations, Case No. PAC-E-20-03, Order No. 34384.

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

A. To mitigate the impact on customers of the requested revenue requirement rate increase, the Company is proposing to use approximately $3.3 million of the remaining TCJA balance to buy down other regulatory asset balances. In particular, the Company is proposing to buy down the following regulatory asset balances: Powerdale Hydro decommissioning costs; Electric Plant Acquisition Adjustment for Craig and Hayden plants; 2017 Protocol equalization adjustment; Intervenor funding; and Cholla closure and decommissioning costs. As discussed by Mr. McDougal, buying down of these regulatory and asset balances reduces the revenue requirement increase by $1.1 million per year.

Q. What is the Company's proposal regarding the remaining $8.5 million of the TCJA deferred tax balance?

A. The Company has not reflected ratemaking treatment to return the remaining TCJA balance to customers in this initial filing because of a potential increase in the federal corporate income tax rate that may occur during the pendency of this proceeding. In April, the Treasury Department announced plans to seek an increase in the corporate tax rate from 21 percent to 28 percent to help fund the White House's economic agenda.[27] Accordingly, committing now to a proposed treatment for the remaining TCJA balance may not be the best result for customers should there be an increase in the federal corporate income tax rate. However, in the event an increase in the corporate tax rate is not enacted this year, the Company proposes to refund the remaining

[27] *See, e.g.,* President Biden Unveils Plan to Raise Corporate Taxes - The New York Times (nytimes.com).

$8.5 million TCJA balance to customers through Schedule 197 over two years, beginning January 1, 2022. A refund over two years would help offset and effectively phase-in the base rate increase in this case. The Company will continue to monitor the potential for an increase to be passed by the Congress and provide an update in rebuttal.

VI. INTERRUPTIBLE PRODUCTS PROVIDED BY P4 PRODUCTIONS

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 Company's proposals for the economic valuation of the interruptible products provided by P4 Productions (Bayer), which acquired the Monsanto Company in 2018, and to establish the interruptible credit amount for inclusion in a P4 Electric Service Agreement ("P4 Agreement").

Q. Why is the Company proposing to change the valuation of the interruptible product and establish a credit?

A. The Commission has previously directed the Company to address the economic valuation of interruptible products offered by Monsanto in a general rate case. In its Order approving a 2005 agreement with Monsanto, the Commission directed the Company to address interruptible product valuation in the context of a general rate case when Monsanto's cost of service is determined. [28] When the Company filed its next rate case, it was in the process of negotiating a new contract with Monsanto and so it did not address the economic evaluation of interruptible products offered by Monsanto

[28] In the Matter of the Application of PacifiCorp dba Rocky Mountain Power for Approval of an Electric Service Agreement with Monsanto Company, Case No. PAC-E-06-09, Order No. 30197 (Dec. 18, 2006).

until later in the proceeding.[29] The Commission found that the Company should have filed the information earlier and directed the Company to continue the existing interruptible credit and terms of service until February 28, 2011.[30] In the Company's 2011 Rate Case, the Commission made findings concerning Monsanto's interruptible products and value. As a result, in its direct case in this filing, the Company is proposing an economic valuation of the interruptible products being discussed to be provided by Bayer and to establish the interruptible credit amount for inclusion in the P4 Agreement. While the Company and Bayer have met regularly and continue discussions to negotiate the terms of a new agreement, at this point we have not reached a full agreement with Bayer.

Q. What is the Company proposing regarding the valuation of the interruptible product provided by P4 Productions to the Company and interruptible credit?

A. If the Company and Bayer do not reach agreement on another value, the Company is proposing an annual value for the interruptible products based on current circumstances. Mr. Eller discusses the specifics of the Company's updated calculation.

Q. What is the status of the negotiations between the Company and Bayer regarding a new energy service agreement?

A. As discussed further by Mr. Eller, the Company and Bayer have been engaged in good faith contract negotiations since August 2019 and hope to execute a contract prior to the conclusion of this proceeding. The Company has also been working with Bayer to facilitate its goal to be carbon-neutral by the year 2030 while ensuring that the

[29] In the Application of PacifiCorp dba Rocky Mountain Power for Approval of Changes to its Electric Service Schedules, Case No. PAC-E-10-07, Order No. 32098 (Oct. 22, 2010).
[30] Id.

Company's customer rates are not negatively impacted.

VII. RECOMMENDATION

Q. Please summarize the Company's recommendation.

A. I recommend the Commission approve the Company's requested base rate increase of approximately $19.0 million, along with the 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.