ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 West North Temple
Salt Lake City, Utah 84116

June 19, 2020

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

Re: Docket 18-035-36
Application of Rocky Mountain Power for Authority to Change its Depreciation Rates Effective January 1, 2021
Direct testimony on issues related to the second phase of the Depreciation Docket

Pursuant to the June 9, 2020 Scheduling Order, Notice of Technical Conference, Notice of Hearings, and Notice of Public Witness Hearing of the Public Service Commission of Utah ("Commission"), Rocky Mountain Power ("Company") hereby submits its direct testimony on issues related to the second phase in the above referenced matter.

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

By E-mail (preferred)	datarequest@pacificorp.com jana.saba@pacificorp.com emily.wegener@pacificorp.com
By Regular Mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward

Joelle Steward
Vice President, Regulation

cc: Service List Docket No. 18-035-36

Rocky Mountain Power
Docket No. 18-035-36
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Steven R. McDougal

June 2020

Q. Are you the same Steven R. McDougal that provided direct testimony and second supplemental testimony in this proceeding on behalf of PacifiCorp, d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company")?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your Phase II direct testimony?

A. I provide a brief history of the Company's depreciation study docket and the events that led up to the Phase II in this case. My testimony also supports the Company's proposed ratemaking treatment for the retired plant associated with the repowered wind facilities described later in my testimony.

Q. What are the issues that are addressed in Phase II of this docket and how were they determined?

A. The issues to be addressed in Phase II of this proceeding were identified in the Stipulation on Depreciation Rate Changes that was filed on March 19, 2020 and approved on April 20, 2020 ("Stipulation"). There are two specific issues identified in paragraph 18 of the Stipulation that will be addressed in Phase II:

1) Further review of the regulatory treatment of projected incremental decommissioning costs; and
2) Regulatory treatment of the retired plant associated with repowered wind facilities in Docket No. 17-035-39 ("Repowering Docket").

II. HISTORY OF DEPRECIATION PROCEEDING

Q. Please provide a brief history of this proceeding.

A. The Company filed its 2018 depreciation study on September 11, 2018, which requested new depreciation rates effective January 1, 2021. A procedural schedule was established on October 2, 2018 that would have adjudicated the Company's application in the spring of 2019. Subsequently, on December 3-4, 2018 the Company presented preliminary studies on the economic lives of its coal plants as part of its stakeholder meetings in the 2019 Integrated Resource Plan ("2019 IRP"). On December 5-6, 2018, the Multi-State Protocol Broad Review Work Group ("MSP work group") met for its monthly meeting and determined that the final coal studies could affect the parties' opinions of the economic lives of certain thermal units. Therefore the procedural schedule was stayed until November 25, 2019. A new procedural schedule was established and parties engaged in settlement discussions that resulted in the Stipulation.

Q. Can you please summarize the history of the decommissioning studies?

A. On December 3, 2019, the Company filed the 2020 Inter-Jurisdictional Cost Allocation Agreement in Docket No. 19-035-42 ("2020 Protocol"). In Section 4.3.1.1 of the 2020 Protocol, the Company committed to undertake a contractor-assisted engineering study of decommissioning costs for the Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, Hayden and Colstrip coal-fueled resources. These studies were provided as two separate supplemental filings in this docket. The Stipulation identified the decommissioning studies as a Phase II issue to provide parties an opportunity for further regulatory review. Further discussion and support for the studies is presented by Mr. Robert Van Engelenhoven in his Phase II direct testimony in this docket.

Q. Please summarize the history of the retired assets associated with the Company's repowering project.

A. On May 25, 2018, the Commission issued its Report and Order in the Repowering Docket. The Commission concluded that the depreciation study proceeding would be a better forum for addressing the recovery of the retired assets associated with the repowering projects. Due to the timing of the Company's general rate case in Docket No. 20-035-04 ("2020 GRC"), the Stipulation specified that the ratemaking treatment for retired plants associated with the repowered wind facilities approved in the Repowering Docket should be determined in Phase II of this proceeding, including the calculation and amount of the retired plant balance and the period over which and method by which it will be recovered from customers. My testimony provides this information and supports the Company's proposed ratemaking treatment.

III. UPDATED DECOMMISSIONING COSTS

Q. Please describe the Company's proposal for updated decommissioning costs?

A. As described in the testimony of Mr. Van Engelenhoven, the Company completed confidential decommissioning and site reclamation studies dated January 15, 2020 and March 13, 2020 (the "Decommissioning Studies"), which were filed in this proceeding on January 16, 2020 and March 17, 2020, respectively. The impact of the updated decommissioning studies was included in the Company's current Utah general rate case, filed in Docket No. 20-035-04 ("2020 GRC"), as adjustment 6.6 in the Company's revenue requirement calculation.[1]

[1] Docket No. 20-035-04, *Direct Testimony of Steven R. McDougal*, at pages 30-31.

Q. Are other plant closure costs included in the Company's 2020 GRC?

A. No. The studies identified other plant closure costs that are necessary for the Company to fully recover all costs associated with closing a plant. For example, each generation plant requires materials and supplies inventory to operate the plant. In the event of a plant closure, those material and supplies will no longer be required and often cannot be absorbed for use at a different generation facility. These costs were not included in the 2020 GRC and Company would seek recovery of any unusable material and supplies inventory in addition to all of the other incurred or expected plant closure costs in a future filing.

IV. REGULATORY TREATMENT OF RETIRED ASSETS

Q. Please describe the calculation of actual depreciation expense?

A. As described in the Company's Application for Approval of Resource Decision to Repower Wind Facilities, filed in Docket No. 17-035-39, depreciation expense is calculated by taking the currently approved depreciation rates multiplied by the gross electric plant-in-service (“EPIS”) balance.

Q. Please describe the Company’s accounting treatment for equipment replaced as part of wind repowering?

A. As existing wind generation equipment is replaced through repowering, the Company transfers the replaced assets from gross EPIS to the accumulated depreciation reserve (“ADR”). The Company’s accounting treatment is consistent with Federal Energy Regulatory Commission (“FERC”) regulations and allowed by Generally Accepted Accounting Principles. The original investment is transferred from FERC account 101, EPIS, to account 108, ADR, by crediting EPIS and debiting the ADR. This entry does not change the Company's net plant balance. The remaining original investment plus new capital additions are depreciated using the existing approved depreciation rates. The current depreciation expense will continue until January 1, 2021, when the rates determined in this docket will be included in rates.

Q. How will the remaining balance of the replaced plant be recovered?

A. The plant balances associated with the wind facilities, including the replaced equipment, are included in the net plant balances used in developing the new depreciation rates approved in this docket.

Q. Over what period will these assets be recovered?

A. The new depreciation rates are designed to recover the remaining plant balance, including the replaced assets, over the approved remaining lives of the wind projects.

Q. Is the remaining balance of the replaced plant balances included in rate base?

A. Yes. As described above, as existing wind generation equipment is replaced by repowering, the Company is transferring the replaced assets from gross EPIS to the ADR. There is no change to net plant or rate base.

Q. Does including the balance in rate base benefit the Company?

A. No. Including the net plant balances allows for the Company to get a full recovery of its cost, including an appropriate return on rate base as set by this Commission, but does not provide a benefit to the Company.

Q. Is recovery of the replaced plant balances consistent with the economic analysis of the repowering project?

A. Yes. All of the repowering economic analysis assumed that the existing plant balances would be fully recovered by the Company, including a return on rate base.

Q. Would it be possible to recover the remaining plant balance of the replaced equipment over a shorted period of time?

A. Yes. This could be accomplished by increasing the depreciation rates to effectively pay off the remaining plant balance over a shorter period of time.

V. RECOMMENDATION

Q. Please summarize the Company's recommendation.

A. I recommend the Commission approve the Company's requested regulatory treatment of the retired assets associated with the repowering project.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Docket No. 18-035-36
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Robert Van Engelenhoven

June 2020

I. INTRODUCTION 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 Robert Van Engelenhoven and my business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am currently employed as Resource Development Director. I am testifying on behalf of the Company.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science in Civil Engineering from Iowa State University and am a licensed structural engineer in Utah and a licensed professional engineer in Wyoming. I have managed major capital projects for the Company for over 20 years.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in Phase II of this case?

A. The purpose of my testimony is to discuss and provide background regarding the confidential decommissioning and site reclamation studies dated January 15, 2020 and March 13, 2020 (the "Decommissioning Studies"), which were filed in this proceeding on January 16, 2020 and March 17, 2020, respectively. I discuss the scope of the Decommissioning Studies and the differences from previous plant decommissioning estimates, and summarize the costs estimated in the Decommissioning Studies.

Q. Please summarize your direct testimony.

A. My testimony demonstrates that the updated decommissioning and remediation costs in the Decommissioning Studies are a reasonable estimate to be included in depreciation rates to be finalized in this docket and incorporated into the revenue requirement as discussed by Mr. Steven R. McDougal. The estimates were developed by an independent engineering consultant, with review and input by other independent contractors, and were prepared and filed consistent with the 2020 Protocol.

III. 2020 DECOMMISSIONING STUDIES

Q. Please explain the responsibilities of the Company employees who work within the Business Policy and Development organization and how that work relates to decommissioning and site reclamation of PacifiCorp's coal-fueled generation resources.

A. Staff within this organization are responsible for preparing decommissioning scopes of work, procuring studies and environmental assessments, coordinating with the Company's operations, environmental, regulatory, and compliance teams, engaging the competitive market in decommissioning and site remediation contracting, and ultimately managing execution of site decommissioning and reclamation projects for PacifiCorp's owned and operated coal-fueled generation resources.

Q. Why did the Company conduct the Decommissioning Studies?

A. Through PacifiCorp's Multi-State Process negotiations, the signatories to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2020 Protocol") agreed that the Company should conduct a thorough study of decommissioning and site reclamation costs for certain coal-fueled generation resources.[1]

Q. Please describe the scope of the Decommissioning Studies.

A. The scope of work for the Decommissioning Studies include the following

[1] *In the Matter of Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, 2020 Protocol Sections 4.3.1.1-4.3.1.2, attached as Exhibit RMP___(JRS-1) to the Direct Testimony of Joelle R. Steward in support of the Company's Application (Dec. 3, 2019). The Company's Application for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement was approved on April 15, 2020.

requirements:

- Provide an owner-informed, overall decommissioning design basis to be used for all of the generating facilities in the study. The design basis established the fundamental assumptions for the cost estimates provided in the final Decommissioning Studies.
- Provide a Class 3 cost estimate to identify of all of the costs for the decommissioning, demolition, reclamation, and remediation of the Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, and Hayden, and Colstrip generating facilities.
- Provide a narrative report describing the entities involved, process used to prepare the report, and assumptions.
- Provide a spreadsheet report incorporating the Association for the Advancement of Cost Engineering ("AACE")[2] Class 3 cost estimates inclusive of certain owner provided Asset Retirement Obligation ("ARO") cost estimates as verified by the third-party study provider.
- Provide cost estimates based on fourth quarter 2019 dollars.

Q. Why were PacifiCorp's other coal-fueled generation facilities not included in the Decommissioning Studies?

A. PacifiCorp's owned, but not operated generation units, Cholla Unit 4 and Craig Units 1 and 2, were not included in the Decommissioning Studies because those units had common depreciable lives proposed for all states in the most recent depreciation study

[2] AACE is a 501(c)(3) non-profit professional association founded in 1956 that offers publications, practice guides, education, certification and recommended practices for cost estimating.

and common retirement dates in the 2019 Integrated Resource Plan.[3]

Q. Who conducted the Decommissioning Studies for the Company?

A. The Decommissioning Studies were performed by independent engineering consultant Kiewit Engineering Group Inc., with input from independent contractors with direct experience decommissioning coal-fueled facilities and site reclamation. The studies included review and input from an independent demolition contractor North American Dismantling Corporation and independent hazardous materials abatement contractors Winter Environmental and ARC Abatement. Two additional independent demolition contractors, Bierlein Companies, Inc. and Brandenburg Industrial Service Company, also reviewed the Decommissioning Studies results.

Q. Is the Company planning to conduct separate decommissioning studies for Cholla Unit 4 and Craig Units 1 and 2?

A. Arizona Public Service Company, the operator of the Cholla generation facility, has retained APTIM Corporation to study the decommissioning and demolition costs for the entire Cholla generation facility, including Cholla Unit 4. APTIM Corporation's evaluation is complete, and the Company is working with APS to determine the fair allocation of the decommissioning costs for Cholla 4 and plant common facilities. A decommissioning and demolition study for the Craig facility will be completed by no later than 2024 in accordance with the 2020 Protocol.

Q. Please describe the difference between the Decommissioning Studies and previous decommissioning estimates prepared by the Company?

A. The Decommissioning Studies provide an AACE Class 3 estimate for demolition,

[3] *PacifiCorp's Integrated Resource Plan (IRP) for 2019*, Docket No. 19-035-02 (Oct. 18, 2019).

salvage, and scrap costs for the facilities studied. An AACE Class 3 cost estimate has an expected accuracy of minus 20 percent to plus 30 percent. The typical purpose of a Class 3 estimate is for budget authorization or control.

Previous decommissioning cost estimates were extrapolated from AACE Class 5 estimates for demolition of a limited subset of PacifiCorp's owned and operated coal-fueled facilities. A Class 5 study has an expected accuracy of minus 50 percent to plus 100 percent. The typical purpose of a Class 5 estimate is for concept screening. It should also be noted that the underlying scope and design basis for the previous decommissioning cost estimates was refined and expanded in response to scoping feedback from stakeholders during the Multi-State Process discussions.

Q. Please describe the major differences between the previous estimates and the current Decommissioning Studies.

A. The differences between the previous estimates and the current Decommissioning Studies are primarily in the method, estimate class, scope, assumptions for ARO and environmental liabilities, site reclamation, owner's costs and contractor indirect costs applied in the current Decommissioning Studies.

Q. What is the change to the method of estimating decommissioning costs used in the Decommissioning Studies?

A. The previous estimates developed demolition costs and salvage values for three coal-fueled generating facilities that were intended to be generally representative of the broader coal-fueled generating fleet. The cost of demolition and salvage for the generating facilities that were not directly studied were extrapolated to establish estimates using generally comparable generating facilities that had been studied.[4] The current Decommissioning Studies estimate the cost and salvage values for each generating facility individually.

Q. Were there other changes in the scope of the estimate in the Decommissioning Studies compared to the previous studies?

A. Yes. The scope of the previous estimates was focused primarily at a facility level and limited to individual generating units. The previous estimates did not include infrastructure and utilities outside the plant perimeter. The current studies focused on individual units as well as all common plant facilities, both inside and outside the facility perimeter.

Q. How were ARO addressed in the Decommissioning Studies?

A. During the time between the previous estimates and the current studies, the scope and cost of AROs changed as existing obligations were completed and new obligations were incurred. In addition, the scope of the current studies included reviewing the cost of the Company's ARO estimates. Where the consultant found that the consultant's estimate for an ARO was significantly different than the Company's estimate, the consultant included their estimate for the ARO in the Decommissioning Studies. The net result was a total increase of approximately $15 million.

Q. Did the Decommissioning Studies address site reclamation?

A. Yes. The previous estimates did not include site reclamation. The current Decommissioning Studies include site reclamation at an estimated average cost of $9.8 million per generating facility. Reclamation scope assumptions include grading to

[4] *See also*, Direct Testimony of Chad A. Teply in support of the Application, at 12 (Sept. 11, 2018).

meet permit conditions and match existing terrain as much as reasonably possible, installing top soil, and seeding for native plants. Top soil installation and seeding was not estimated for Wyodak, due to its co-location with non-PacifiCorp generation resources in an energy hub.

Q. How did the Decommissioning Studies address owner's costs and contractor indirect costs?

A. The previous estimates did not include owner's project development and oversight costs or itemized competitive market contractor indirect costs. The current Decommissioning Studies includes owner's project development and oversight costs. Owner's costs include the cost of preparing the facility for the work, project management, long-lead permitting, and site demolition management.

Q. Please summarize the results of the Decommissioning Studies.

A. Confidential Exhibit RMP__(RV-1) contains a table showing the results of the Decommissioning Studies excluding certain closure-related costs that may be considered outside of decommissioning costs or require additional steps to refine their accuracy.

Q. What costs were included in the total base decommissioning and demolition costs for each facility?

A. In general terms, the base decommissioning costs include the costs to: (1) develop the decommissioning project, including the site investigation; (2) conduct the decommissioning of the facility, decontaminating activities, and preparing of the facility for the demolition contractor; (3) complete the dismantling and demolition of the facility less the offset value of salvage and scrap; (4) complete the ARO, site remediation, and site reclamation; and (5) the estimates of competitive market contractor margin and indirect costs. The costs and offsets were adjusted to PacifiCorp ownership values for each facility studied.

Q. Were there any offsets to the estimated base decommissioning and demolition costs?

A. Yes. Demolition costs are offset by the value of salvage and scrap. Estimated salvage value is based on the projected value of equipment, materials, and commodities that could be sold. Estimated scrap value is based on the estimated then-current market prices of steel, titanium, copper based metals, and other valuable metals.

Q. Do the Decommissioning Studies incorporate other costs in relation to decommissioning?

A. Yes. Other costs incorporated in the Decommissioning Studies that may be considered outside of decommissioning costs include: (1) assets for which cost recovery is accounted for through mechanisms other than depreciation; (2) assets that do not present an immediate hazard, nuisance, or need to decommission and remediate, including asbestos coated piping; (3) coal pile subsurface excavation and remediation and above-ground asbestos remediation costs that have been estimated, but will be further evaluated in the next steps; and (4) material and supply inventory and rolling stock dispensation. As discussed in the direct testimony of Mr. McDougal, these other costs were not reflected in the revenue requirement request in the 2020 GRC.

Q. Is PacifiCorp conducting other efforts to more accurately estimate the decommissioning costs?

A. Yes. The Decommissioning Studies assumed removal of 10 feet of coal-laden soil under the current coal piles at each facility. The Company is planning to conduct a coal pile boring study to improve the coal pile subsurface excavation, remediation, and haul off cost estimate for each facility studied. The Company is also planning to conduct an asbestos study for each facility studied to improve asbestos abatement costs.

Q. Are these the Company’s final estimates for decommissioning costs?

A. No. The 2020 Protocol contemplates an update of the Decommissioning Studies in 2024 to address the Craig, Hunter, Huntington, and Wyodak coal-fueled resources. That study will update the estimated decommissioning costs so that depreciation rates for Craig[5] and the longer-lived resources (i.e. Hunter, Huntington, and Wyodak) can be updated to reflect more accurate and contemporaneous decommissioning estimates. Further, as I discussed previously, the operator of Cholla Unit 4 is separately estimating decommissioning and site reclamation costs for that unit.

VI. CONCLUSION AND RECOMMENDATION

Q. Please summarize your testimony.

A. I recommend that the Commission approve the incremental decommissioning costs as determined by an independent third-party contractor, presented in my testimony, and included in the revenue requirement calculation as discussed by Mr. McDougal.

Q. Does this conclude your direct testimony?

A. Yes.

---

[8] PacifiCorp’s ownership share is 19 percent of Craig Unit 1 and 19 percent of Craig Unit 2.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RV-1)
Docket No. 18-035-36
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Redacted Exhibit Accompanying Direct Testimony of Robert Van Engelenhoven

TPT Demolition Summary

May 2020

REDACTED

CONFIDENTIAL - SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULES 746-1-602 AND 603

Description	Hunter	Huntington	D Johnston	J Bridger	Naughton	Wyodak	Hayden	Colstrip 3&4†
1 Site Investigation and Development	[redacted]							
2 Decommissioning - Owner scope								
3 Pre-demolition Decontamination								
4 Net of Demolition, Salvage, and Scrap								
5 Reclamation								
6 Demolition Contractor Plant Specific Items								
Demolition Contractor Subtotal - Categories 3 thru 6 above								
Gross Cost	[redacted]							
Salvage/Scrap Offset								
Net Cost								
7 Owner Plant Specific AROs								
9 Demolition Contractor Project Indirects								
10 BASE ESTIMATE Subtotal, before Contingency								
Gross Cost	[redacted]							
Salvage/Scrap Offset								
Net Cost								
11 Contingency								
12 Net Cost								
13 PacifiCorp Ownership Percentage of the Plant	84.687%	100.000%	100.000%	66.667%	100.000%	80.000%	17.500%	10.000%
14 PacifiCorp Share of BASE ESTIMATE Total, including Contingency								
Gross Cost	[redacted]							
Salvage/Scrap Offset								
Net Cost								

† - Colstrip Unit 1 - 4 common facility costs converted to Colstrip Unit 3 - 4 costs by mulitplying by 58%.

CERTIFICATE OF SERVICE

Docket No. 18-035-36

I hereby certify that on June 19, 2020, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services

Cheryl Murray	cmurray@utah.gov
Michele Beck	mbeck@utah.gov

Division of Public Utilities

dpudatarequest@utah.gov

Assistant Attorney General

Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Robert Moore	rmoore@agutah.gov
Victor Copeland	vcopeland@agutah.gov

Rocky Mountain Power

Data Request Response Center	datarequest@pacificorp.com
Emily Wegener	emily.wegener@pacificorp.com
Jana Saba	jana.saba@pacificorp.com;
	utahdockets@pacificorp.com

Western Resource Advocates

Sophie Hayes **(C)**	sophie.hayes@westernresources.org
Nancy Kelly **(C)**	nkelly@westernresources.org
Steven S. Michel **(C)**	smichel@westernresources.org

Utah Clean Energy

Hunter Holman **(C)**	hunter@utahcleanenergy.org
Sarah Wright **(C)**	sarah@utahcleanenergy.org

Sierra Club

Julian Aris **(C)**	julian.aris@sierraclub.org
Gloria Smith	gloria.smith@sierraclub.org
Ana Boyd **(C)**	ana.boyd@sierraclub.org

Utah Association of Energy Users

Gary A. Dodge	gdodge@hjdlaw.com
Phillip J. Russell **(C)**	prussell@hjdlaw.com

Mary Penfield
Adviser, Regulatory Operations