ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

September 11, 2018

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 18-035-36—In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for Authority to Change its Depreciation Rates Effective January 1, 2021**

Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or "Company"), applies to the Public Service Commission of Utah for an order authorizing the Company to change depreciation rates effective January 1, 2021. As requested by the Commission, Rocky Mountain Power is also providing seven (7) printed copies of the filing via overnight delivery.

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

By E-mail (preferred): datarequest@pacificorp.com
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Jana.saba@pacificorp.com
yvonne.hogle@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
Vice President, Regulation

cc: Service List

CERTIFICATE OF SERVICE

Docket No. 18-035-36

I hereby certify that on September 11, 2018, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

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Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority To Change its Depreciation Rates Effective January 1, 2021	))))))	DOCKET NO. 18-035-36 **APPLICATION**

Pursuant to Utah Code Ann. § 54-4-24 and Rule 746-310-7 of the Utah Administrative Code, Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or the "Company"), hereby submits this application ("Application") to the Public Service Commission of Utah ("Commission") for an order authorizing the Company to change depreciation rates effective January 1, 2021, consistent with the Company's Depreciation Study, described in more detail in testimony and exhibits supporting this Application and generally referenced below ("Depreciation Study").

In support of this Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is an electrical corporation and public utility operating in the state of Utah and is subject to the jurisdiction of the Commission with regard to its public utility operations. PacifiCorp has two retail electric service divisions, Rocky Mountain Power and Pacific Power. Rocky Mountain Power provides retail electric service in Utah, Idaho, and Wyoming, and Pacific Power provides retail electric service in California, Oregon, and Washington.

2. This Application is filed pursuant to Utah Code Ann. §54-4-24 and R746-310-7 of the Utah Administrative Code, which authorizes the Commission to prescribe the rates of depreciation to be used by any public utility subject to its jurisdiction.

3. Communications regarding this Application should be addressed to:

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In addition, Rocky Mountain Power requests that all data requests regarding this Application be addressed to:

By email (preferred)	datarequest@pacificorp.com
By regular mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

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

4. The Company last performed a depreciation study approximately five years ago. The Commission authorized the current Company depreciation rates in its Order Confirming Bench Ruling Approving Stipulation on Depreciation Rate Changes, issued November 7, 2013, with rates effective January 1, 2014, in Docket No. 13-035-02.

5. The Company has performed the updated Depreciation Study, attached to Company witness Mr. John J. Spanos's direct testimony as Exhibit RMP___(JJS-2). The Company requests authorization to implement the depreciation rates set forth in the Depreciation Study. The study identifies changes that have occurred since the Company's last depreciation study, measures the effect of the changes on the recovery of presently surviving capital, and revises the capital recovery rate. The application of the depreciation rates in the Depreciation Study would increase annual depreciation expense by approximately $100.1 million on a Utah basis, based on projected plant balances as of December 31, 2020, and the inter-jurisdictional allocation methodology currently in effect (the 2017 Protocol approved in Docket Nos. 15-035-86 and 17-035-06). In addition, the proposed termination of excess reserve amortizations also increases the depreciation

expense by approximately $28.0 million on a Utah basis. Combined, the proposed changes would increase depreciation expense by approximately $128.1 million on a Utah basis. The Company proposes to record Depreciation Study recommendations on its books and records beginning with calendar year 2021. Rocky Mountain Power is not requesting as part of this filing that new depreciation rates approved in this docket be reflected in tariff prices at this time. Rather, the Company intends to include the impacts of the Depreciation Study in Utah rates as part of a future regulatory proceeding.

6. In support of this Application, the Company presents the direct testimony of Ms. Nikki L. Kobliha, Vice President, Chief Financial Officer and Treasurer of the Company. Ms. Kobliha supports and describes the development of the Depreciation Study, and describes significant issues related to steam generating facilities that were considered in the Depreciation Study.

7. The Company presents the direct testimony of Mr. John J. Spanos, Senior Vice President of Gannett Fleming, Valuation and Rate Consultants, LLC. Mr. Spanos presents the Depreciation Study, describes how the Depreciation Study was prepared, presents the depreciation rates for which the Company is seeking Commission approval, and discusses the basis for the recommended changes in depreciation rates.

8. The Company presents the direct testimony of Mr. Steven R. McDougal, Director of Revenue Requirements. Mr. McDougal calculates the effect on annual depreciation expense allocated to Utah from applying the proposed depreciation rates to depreciable plant balances. He also describes the Company's recommendations on certain state specific issues, and responds to the reporting requirements from the 2013 depreciation study.

9. The Company presents the direct testimony of Mr. Chad A. Teply, Senior Vice President of Strategy and Development for Rocky Mountain Power. Mr. Teply describes the process used to evaluate the plant depreciable lives for steam and gas generating stations and the procedure used to estimate the retirement date for the Company's gas, wind, and hydroelectric generating resources. He also demonstrates that the estimated retirement dates proposed for the Company's generation plants are reasonable and appropriate for use in the Depreciation Study. Mr. Teply also explains why the rates proposed as terminal net salvage, or "decommissioning costs," in the calculation of depreciation rates for generating plants are reasonable and prudent.

10. Finally, the Company presents the direct testimony of Mr. Timothy J. Hemstreet, Director of Renewable Development for the Company. Mr. Hemstreet describes the Company's repowering wind facilities project and the process of determining an appropriate life for the repowered wind facilities. He also describes the methodology used to estimate the retirement date for the Company wind and hydroelectric generating resources.

11. For administrative and economic efficiencies, the Company strives to maintain uniform utility accounts, including depreciation rates, across its six state service territories. To maintain consistent depreciation rates across all states, the Company is also filing the Depreciation Study in Oregon, Wyoming, Idaho, and Washington. Maintaining consistent depreciation rates across all states avoids multiple sets of depreciation accounts and records that would impose a costly administrative burden on the Company and unnecessary expense for the Company's customers.

III. REQUEST FOR RELIEF

12. For the reasons described above and in the testimony and exhibits supporting this Application, Rocky Mountain Power respectfully requests that the Commission issue an order finding:

a. The Depreciation Study recommendations regarding depreciation rates are proper and adequate depreciation rates for the Company;

b. Adoption of the Depreciation Study's recommendations into Utah electric rates will result in fair and reasonable rates and accurately impose costs on those customers for whom such costs are incurred; and

c. The Depreciation Study's recommended depreciation rates should be reflected in the Company's accounts and records beginning on January 1, 2021.

DATED this 11th day of September, 2018.

Respectfully submitted,

ROCKY MOUNTAIN POWER

Yvonne R. Hogle

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Attorney for Rocky Mountain Power

Rocky Mountain Power
Docket No. 18-035-36
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Nikki L. Kobliha

September 11, 2018

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

A. My name is Nikki L. Kobliha. My business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon, 97232. My present position is Vice President, Chief Financial Officer and Treasurer for PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Bachelor of Business Administration with a concentration in Accounting from the University of Portland in 1994. I became a Certified Public Accountant in 1996. I joined the Company in 1997 and have taken on roles of increasing responsibility before being appointed Chief Financial Officer in 2015. I am responsible for all aspects of the Company's finance, accounting, income tax, internal audit, Securities and Exchange Commission reporting, treasury, credit risk management, pension and other investment management activities.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony:

- Summarizes the Company's proposal for new depreciation rates and their effect on annual depreciation expense. The proposed depreciation rates are based on projected December 31, 2020 plant balances. The proposed depreciation rates are contained in the "Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2017" (the "Depreciation Study"), which was performed on behalf of the Company by Mr. John J. Spanos of Gannett

Fleming Valuation and Rate Consultants, LLC. The Depreciation Study is provided as Exhibit RMP___(JJS- 2) to Mr. Spanos's testimony.

- Provides a description of the development of the Depreciation Study and explains why the depreciation rates resulting from the Depreciation Study are accurate and reasonable.
- Identifies and discusses the main issues considered during the preparation of the Depreciation Study. These issues were addressed in the data provided to Mr. Spanos and, in turn, this data formed the basis for the Depreciation Study and the recommended changes in depreciation rates.
- Introduces the other Company witnesses who will testify in this proceeding and provides a brief description of their respective subject matter.
- Briefly summarizes the Company's recommendations to the Public Service Commission of Utah ("Commission").

RESULTS OF THE DEPRECIATION STUDY

Q. Please explain the depreciation rates for which the Company is seeking Commission approval in this proceeding.

A. The Company seeks Commission approval of the depreciation rates contained in the Depreciation Study based on December 31, 2020 projected balances as shown in the Appendix of the Depreciation Study provided in Exhibit RMP___(JJS-2) on page 1393 and as summarized in Mr. Spanos's testimony.

Q. Please explain how the depreciation rates were developed.

A. The Company instructed Mr. Spanos to use December 31, 2017 historical data as the basis for his depreciation life study analysis, which was then used to develop depreciation rates based on projected December 31, 2020 balances. This process is further described in Mr. Spanos's testimony. Projecting balances through December 31, 2020 aligns with the January 1, 2021 proposed effective date wherein all anticipated plant additions have been considered when developing the depreciation rates. The reasons for using a January 1, 2021 effective date are provided in Mr. Steven R. McDougal's testimony.

Q. How will the depreciation rates recommended by Mr. Spanos affect annual depreciation expense?

A. The Depreciation Study proposes to increase the current composite depreciation rate of 2.74 percent for the Company's electric utility plant by 0.8 percent system-wide, resulting in a new composite depreciation rate of 3.54 percent as shown in Mr. McDougal's Exhibit RMP___(SRM-1). Applying the recommended depreciation rates to the projected December 31, 2020 depreciable plant balances increases total-Company annual depreciation expense by approximately $228.1 million, compared with the level of annual depreciation expense developed by application of the currently authorized depreciation rates to the same plant balances.

Adoption of the proposed depreciation rates increases annual Utah depreciation expense by approximately $100.1 million, based on projected December 31, 2020 depreciable plant balances. In addition, the Company has assumed the current excess reserve amortizations stipulated in the 2013 depreciation study, Docket No. 13-035-02 ("2013 depreciation study") will be eliminated, as further described in Mr. McDougal's testimony. Eliminating this excess reserve amortization increases Utah's jurisdictional depreciation expense by $28.0 million. The calculation of the Utah jurisdictional amount under the 2017 Protocol allocation methodology is described in Mr. McDougal's testimony.

DEPRECIATION STUDY BACKGROUND

Q. Please explain the concept of depreciation.

A. There are many definitions of depreciation. The following definition was offered by the American Institute of Certified Public Accountants in its Accounting Research Bulletin #43:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.

The actual payment for an electric utility plant asset occurs in the period in which it is acquired through purchase or construction. Depreciation accounting spreads this cost over the useful life of the asset. The fundamental reason for recording depreciation is to accurately measure a utility's operating costs. Capital investments in the buildings, plant, and equipment necessary to provide electric service are essentially a prepaid expense, and annual depreciation allocates that prepaid expense applicable to each successive accounting period over the service life of the asset. Annual depreciation is important and essential in informing investors and others of a company's periodic income. If it is omitted or distorted, a company's periodic income statement is distorted and would not meet required accounting and reporting standards.

Q. Why is depreciation especially important to an electric utility?

A. An electric utility's business is capital intensive; that is, it requires a continuous investment in generation, transmission, and distribution equipment with long lives to provide electric service to customers. The annual depreciation of this equipment is a major component of expense to the utility. Regulated electric rates are set to allow the utility the opportunity to fully recover its operating costs, earn a fair return on its investment, and equitably distribute the cost of the assets to customers using the facilities. If depreciation rates are established at an unreasonably low or high level for ratemaking purposes, the utility will not recover its operating costs in the appropriate period, which will shift either costs or benefits from current customers to future customers.

Q. Why was it necessary for the Company to conduct the Depreciation Study?

A. It is prudent accounting practice to periodically update depreciation rates to recognize additions to investment in plant assets and to reflect changes in asset characteristics, technology, salvage, removal costs, life span estimates, and other factors that impact depreciation rate calculations. The Company conducts depreciation studies as it deems appropriate or as mandated by the Commission. The Company's last depreciation study was conducted approximately five years ago. The Commission authorized the Company's current depreciation rates in its Order Confirming Bench Ruling Approving Stipulation on Depreciation Rate Changes, issued November 7, 2013, with rates effective January 1, 2014. The Order required the Company to file a new depreciation study by September 11, 2018.

Q. Was the Depreciation Study prepared under your direction?

A. Yes. As Vice President, Chief Financial Officer and Treasurer, I am responsible for the Company's corporate accounting departments and for ensuring compliance with

Company accounting policies and procedures. This includes periodic review and study of depreciation rates.

Q. Do you believe that the estimated plant depreciable lives and depreciation rates developed in the Depreciation Study result in a fair level of depreciation expense for customers to reimburse the Company for its investment in electric utility plant and equipment?

A. Yes, I believe that the Depreciation Study is well supported by the underlying engineering and accounting data, and that the resulting depreciation rates produce an annual depreciation expense that is fair and reasonable for both financial reporting and ratemaking purposes.

Q. What is the basis for your conclusions about the Depreciation Study?

A. A good depreciation study is the product of sound analytical procedures applied to accurate, reliable accounting and engineering data. I have reviewed Mr. Spanos's work in preparing the Depreciation Study, and I concur with his methodologies and application of analytical procedures as described in his testimony. With respect to data inputs, Mr. Spanos used the estimated economic lives for thermal generation plants provided by the Company, as further explained in Mr. Chad A. Teply's testimony. Mr. Spanos used the estimated economic lives for wind and hydro plant provided by the Company, as further explained in Mr. Timothy J. Hemstreet's testimony. Depreciable life estimates for other types of plant and equipment are based on Mr. Spanos's actuarial analysis of the data and were reviewed for reasonableness by the Company. The accounting data has also been carefully and consistently prepared. I recommend approval of the rates contained in the Depreciation Study.

SIGNIFICANT ISSUES

Q. What are the steam generating facilities-related issues the Company considered in the Depreciation Study?

A. The Company considered:

- Recognizing the impact of incremental capital additions;
- Shortening of the terminal lives for several of the Company's coal-fired units;
- Shifting group depreciation from a plant level to a unit level; and,
- Changing the method used to determine decommissioning costs for each steam generating facility.

Q. Explain the impact of capital additions to the Company's steam generating facilities.

A. Additions to property, plant and equipment balances, more commonly referred to as capital additions, are one of the primary drivers that increase depreciation expense. Because the Company's steam facilities have set terminal lives, incremental capital additions have to be depreciated over a shorter remaining life. Further explanation of the need for these additions is included in Mr. Teply's testimony.

Q. Is this a new issue for steam generating facilities?

A. No. This issue was identified in previous studies where the Company proposed to include projected capital additions in the development of depreciation rates to help mitigate potential future depreciation increases. The Commission's adoption of depreciation rates arising out of those studies did not allow recognition of any capital additions occurring after the implementation of those rates.

Q. Did the Company consider extending the depreciation lives of the steam generating facilities to mitigate the increase in depreciation expense?

A. No. There is uncertainty regarding the period in which steam generating facilities will be allowed to continue to operate due to existing, evolving or emerging environmental regulations. Given this, the Company does not recommend extending the depreciation lives of the steam generating facilities. Instead, the Company recommends retaining 61 years, as previously approved by the Commission, and in certain cases shortening the depreciable terminal life of steam generating facilities.

Q. For which steam generating facilities is the Company recommending to shorten the terminal life?

A. The Company is recommending shortening the terminal lives of the following steam generation facilities: Cholla Unit 4, Colstrip Plant, Craig Plant and Jim Bridger Plant Unit 1 and Unit 2, as further explained and discussed in Mr. Teply's testimony.

Q. Describe the accounting treatment for the retirement of Naughton Unit 3.

A. As referenced in Exhibit RMP___(CAT-1) of Mr. Teply's testimony, Naughton Unit 3 is projected to be retired in 2019, prior to the proposed January 1, 2021 implementation date of this Depreciation Study. Consistent with the composite or group procedure of depreciation[1] the Company applies to all facilities, the cost of the retired unit is included in Naughton Plant's depreciation reserve.

Q. Explain the change made to the Company's group method of depreciation for steam generating facilities.

A. In the 2013 depreciation study, depreciation for steam facilities were grouped by

[1] The group depreciation procedure is discussed in Part V of Exhibit RMP___(JJS-2) to Mr. Spanos' testimony.

Federal Energy Regulatory Commission ("FERC") account at a plant level, merging all units within one facility into one common group. For this Depreciation Study, steam facilities are grouped by FERC account at a unit level. This shift in methodology allows the Company the flexibility to retire different units in different years.

Q. Please explain the adjustment made to decommissioning costs for steam generating facilities.

A. In the 2013 depreciation study, the Company determined the decommissioning cost at each facility by applying $40 per kW. In this Depreciation Study, the Company has provided plant-specific estimates of decommissioning costs, as further explained in Mr. Teply's testimony.

Q. Has the Company changed any of the significant issues considered for hydroelectric facilities lives in this Depreciation Study?

A. No. The 2013 depreciation study based hydroelectric plant terminal lives primarily on FERC hydroelectric plant license termination dates. For this Depreciation Study, the Company continued to use the FERC hydroelectric plant license termination dates and has updated those lives where new licenses have been issued or are estimated to be reissued within the next five years.

Q. Please discuss the other hydroelectric facilities-related issues you considered in this Depreciation Study.

A. The 2013 depreciation study included removal costs for hydroelectric facilities where the Company has entered into negotiations or settlements to remove those facilities, as well as a decommissioning reserve for minor hydroelectric facilities that may be removed in the near future. The Company has updated the Depreciation Study to reflect the current projection for small plants where the Company has estimated some probability of their decommissioning in the near future. This reserve is not intended to cover the decommissioning or removal of any large facility.

Q. Please discuss the wind generation facilities-related issue in the Depreciation Study.

A. The Company will repower many of its wind generation facilities in 2019 and 2020. The estimated balances in the Depreciation Study schedule for projected plant balances as of December 31, 2020, reflect both the new investment in plant due to the repowering, as well as the retirement of wind turbine equipment associated with the repowered assets, with the retirement costs included in the depreciation reserve. The treatment of retired wind turbine equipment included in the depreciation reserve is consistent with the composite or group procedure of depreciation the Company applies to all facilities. With the repowering of the wind generation facilities, the Company is recommending extending the terminal lives of wind generation facilities to be 30 years from the time of repowering, as discussed further in Mr. Hemstreet's testimony.

Q. Please discuss the natural gas generation facilities-related issue in the Depreciation Study.

A. Since the 2013 depreciation study, the Company has continued to experience interim retirements related to scheduled overhauls on its natural gas facilities. This interim retirement experience has allowed the Company to provide Mr. Spanos with additional historical retirement data to aid in his analysis and determination of interim retirement patterns used in the calculation of the composite remaining lives. Changes to the projected future interim retirements have contributed to an increase in depreciation expense.

Q. Were there any significant changes in the Depreciation Study related to transmission, distribution, and general plant assets?

A. No. The Company provided Mr. Spanos with the historical data for transmission, distribution, and general plants assets including removal costs, salvage, and third-party accommodation payments related to removal costs, to use in determining the proposed depreciation lives and rates. There were no significant changes to the depreciation lives and rates for these assets, outside of those which would normally result from updating the study.

Q. Are there any significant changes related to mining facilities in this study?

A. Yes, the Utah mine has been removed from this Depreciation Study. Since the 2013 study, the Company's Deer Creek mine was closed and mine reclamation is underway.

INTRODUCTION OF WITNESSES

Q. Who is testifying on behalf of the Company in support of the Company's Application?

A. Four other witnesses testify on behalf of the Company: Mr. John J. Spanos, Senior Vice President of Gannett Fleming Valuation and rate Consultants, LLC.; Mr. Steven R. McDougal, Director of Revenue Requirements; Mr. Chad A. Teply, Senior Vice President of Strategy and Development; and Mr. Timothy J. Hemstreet, Director of Renewable Energy Development.

Mr. Spanos presents the Depreciation Study and the depreciation rates for which the Company is seeking Commission approval. He describes how the Depreciation

Study was prepared and discusses the basis for the recommended changes in depreciation rates.

Mr. McDougal describes the jurisdictional allocation of the Depreciation Study to Utah and how the new study complies with and responds to reporting requirements from the 2013 depreciation study.

Mr. Teply describes the process used by Company's engineers to evaluate the current approved plant depreciable lives for steam and natural gas generating facilities and to estimate the retirement date for those generating facilities. Mr. Teply demonstrates that the estimated retirement dates proposed by the Company for generation plants are reasonable, prudent, and are appropriate inputs for Mr. Spanos's depreciation analysis. Mr. Teply also explains why the amounts the Company proposes to include as terminal net salvage, or "decommissioning costs," in the calculation of depreciation rates for generating plants, are reasonable and prudent.

Mr. Hemstreet describes the Company's repowering project for its wind facilities and the process of determining an appropriate life for the repowered wind facilities. He also describes the procedure used to estimate the retirement date for the Company's hydroelectric generating stations. He demonstrates that the estimated retirement dates proposed by the Company for wind and hydroelectric generation plants are reasonable, prudent, and are appropriate inputs for Mr. Spanos's depreciation analysis.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission find that the depreciation rates sponsored by

Mr. Spanos in the Depreciation Study based on projected December 31, 2020 plant balances are fair and reasonable depreciation rates for the Company. I further recommend that the Commission approve the Company's request to implement these depreciation rates in its accounts and records effective January 1, 2021.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Docket No. 18-035-36
Witness: John J. Spanos

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of John J. Spanos

September 11, 2018

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

A. My name is John J. Spanos. I am a Senior Vice President at Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"). My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since college graduation in June 1986.

Q. On whose behalf are you testifying in **this case?**

A. I am testifying on behalf of PacifiCorp d/b/a Rocky Mountain Power (the "Company").

QUALIFICATIONS

Q. Please state your qualifications.

A. Please refer to Exhibit RMP___(JJS-1) for my qualifications.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I sponsor and support the depreciation study titled, "Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2017" (the "Depreciation Study"), performed for the Company, attached as Exhibit RMP___(JJS-2). The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2017. Based on the Depreciation Study, I recommend approval of the depreciation rates using the projected December 31, 2020 plant and reserve balances. The proposed rates appropriately reflect the rates at which the Company's assets should be depreciated over their useful lives and are based on the most commonly used methods and procedures for determining depreciation rates.

DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value that is not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to consider are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Q. Did you prepare the Depreciation Study filed by the Company in this proceeding?

A. Yes.

Q. Are there guidelines in the preparation of depreciation studies?

A. Yes. In preparing the Depreciation Study, I followed generally accepted practices in the field of depreciation valuation.

Q. How do the methods and procedures of this Depreciation Study compare to those used historically?

A. The methods and procedures of this study are the same as those used in past studies of this Company as well as others before this Commission. Depreciation rates are determined based on the average service life procedure and the remaining life method.

Q. Please describe the contents of the Depreciation Study.

A. The Depreciation Study includes nine parts. Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, describes the methodology of estimating survivor curves. Parts III and IV set forth the analysis used for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, describes the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII, and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2017.

The table on pages VI-4 through VI-21 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2017, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or sub-account. The section beginning on page VII-2 presents the results of the retirement rate and simulated plant analyses prepared as the historical bases for the service life estimates. Finally, the section in the Appendix presents the recommended depreciation rates and parameters as of December 31, 2020.

Q. Please explain how you performed your Depreciation Study.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. Under this methodology, the annual depreciation is determined by distributing the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

Q. In your analysis, how did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. First, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or sub-account identified as having similar characteristics. Second, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life and net salvage study consisted of compiling historical data from records related to the Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. What historical data did you analyze to estimate service life characteristics?

A. I analyzed the Company's accounting entries that recorded plant transactions during the 1937 through 2017 period; however, the earliest year of data varied by account. The transactions included additions, retirements, transfers, sales, and the related balances.

Q. What method did you use to analyze the service life data?

A. I used the retirement rate method for most plant accounts. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the Depreciation Study.

Q. Please describe how you used the retirement rate method to analyze the Company's service life data.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. Did you use any other methods to analyze service life data?

A. Yes. For most distribution assets in Utah and Idaho, the Company accounting records do not include the vintage of each transaction. Therefore, I used the simulated plant record method to determine life characteristics.

Q. What are "Iowa-type survivor curves," and how did you use them to estimate the service life characteristics for each property group?

A. They are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. I used the Iowa curves and truncated Iowa curves in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicates the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 60-R2 indicates an average service life of sixty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 2, for the mode (possible modes for R type curves range from 1 to 5).

Q. What approach did you use to estimate the lives of significant facilities structures such as production plants?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, I describe the survivor characteristics of such facilities by using interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility. For example, for a building, the retirements of its elements include plumbing, heating, doors, windows, roofs, etc., that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has your firm, Gannett Fleming, used this approach in other proceedings?

A. Yes, we have used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada. This technique was applied to develop the current depreciation rates being used by the Company in the same manner recommended in this case.

Q. What are "probable retirement years," and what was your bases for estimating them for each facility?

A. Probable retirement years are life spans for each facility, and my estimates therefore are based on the life assessment study, consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities, and judgment. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirements of these facilities are not yet subject to specific management plans. Such plans would be premature. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. Have you physically observed the Company's plant and equipment in Depreciation Studies you've performed for the Company in the past?

A. Yes. I made field reviews of the Company's property as part of a past study in May and June 2012 to observe representative portions of plant and equipment. I conduct field reviews to become familiar with Company operations and understand the function of the plant and information on the reasons for past retirements and the expected future causes of retirements. I incorporated this knowledge as well as information from other discussions with management in the interpretation and extrapolation of the statistical analyses.

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1992 through 2017 and considered estimates for other electric companies. The net salvage percentages are based on a combination of statistical analyses and informed judgment. The statistical analyses consider the cost of removal and gross salvage ratios to the associated retirements during the 26-year period. I also measured the trends of these data based on three-year moving averages and the most recent five-year indications.

Q. Were the net salvage percentages for generation facilities based on the same analyses?

A. Yes, for the interim analyses. The net salvage percentages for generation facilities were based on two components, the interim net salvage percentage and the final net salvage percentage. The interim net salvage percentage is determined based on the historical indications from the 1992–2017 period, of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. I determined the final net salvage or dismantlement component based on the assets anticipated to be retired at the concurrent date of final retirement.

Q. Have you included a dismantlement component into the overall recovery of generation facilities?

A. Yes. A dismantlement component was included in the net salvage percentage for steam and other production facilities. There is a separate decommissioning reserve for small hydro facilities which are soon to be retired, as the dismantlement component for hydro facilities in the study is zero.

Q. Can you explain how the dismantlement component is included in the Depreciation Study?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the Company's cost estimates, I determined that the dismantlement or decommissioning costs for steam production and other production facilities is best calculated on a $/KW factor based on surviving plant at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculation for each location is set forth on pages VIII-2 through VIII-12 of Exhibit RMP___(JJS-2).

Q. Please describe the second phase of the process that you used in the Depreciation Study in which you calculated composite remaining lives and annual depreciation accrual rates.

A. After estimating the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please illustrate how the annual depreciation accrual rate for a particular group of property is presented in your Depreciation Study.

A. I will use Account 353, Station Equipment, as an example because it is one of the largest depreciable mass accounts and represents approximately nine percent of depreciable plant.

I used the retirement rate method to analyze the survivor characteristics of this property group. I compiled aged plant accounting data from 1924 through 2017 and analyzed it in periods that best represent the overall service life of this property. The life tables for the 1924–2017 and 1988–2017 experience bands are presented on pages VII-95 through VII-97 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-95 shows $2,133,875 retired at age 0.5 with $2,347,756,170 exposed to retirement. Consequently, the retirement ratio is 0.0009 and the surviving ratio is 0.9991. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 58-S0 on page VII-94.

The net salvage percent is presented on pages VIII-49 and VIII-50. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the 1992 through 2017 period. The 26-year period experienced $20,503,595 ($8,621,261-$29,124,856) in net salvage for $179,971,886 plant retired. The result is negative net salvage of eleven percent ($20,503,595/$179,971,886). Although recent trends show more negative indications, I determined that, based on industry ranges and Company expectations, negative ten percent was the most appropriate estimate.

My calculation of the annual depreciation related to the original cost at December 31, 2017, of electric plant is presented on pages IX-299 through IX-301. The calculation is based on the 58-S0 survivor curve, ten percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-18.

CONCLUSION

Q. Please summarize the results of your Depreciation Study.

A. The depreciation rates as of December 31, 2017 appropriately reflect the rates at which the values of the Company’s assets have been consumed over their useful lives to date. These rates are based on the most commonly used methods and procedures for determining depreciation rates. The life and salvage parameters are based on widely used techniques and the depreciation rates are based on the average service life procedure and remaining life method. Therefore, the depreciation rates set forth on pages VI-4 through VI-21 of Exhibit RMP___(JJS-2) represent the calculated rates as of December 31, 2017.

Q. Does your Depreciation Study recommend new depreciation rates based on December 31, 2020 plant and reserve balances?

A. Yes. The depreciation accrual rates set forth in the Appendix to Exhibit RMP___(JJS-2), which begins on page 1393, represent the rates most applicable in this proceeding. These rates use all of the same methods and procedures described in the Depreciation Study but apply the parameters to the projected December 31, 2020 plant and reserve balances. The projected plant and book reserve balances as of December 31, 2020 properly established the most reasonable rate base when the rates will go into effect. Thus, I recommend approval of the depreciation accrual rates in the Appendix as being just and reasonable and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JJS-1)
Docket No. 18-035-36
Witness: John J. Spanos

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John J. Spanos

John Spanos Qualifications

September 11, 2018

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary – Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited, and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company, and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to the position as Vice President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation – New York and Pennsylvania Divisions; The City of Bethlehem – Bureau of Water; The City of Coatesville Authority; The City of Lancaster – Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP;

Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States

Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; and Northern Illinois Gas Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; the Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority;

New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission; and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Co.	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Co.	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Co.	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Co.	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Co.	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Co.	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Co.	Depreciation
47.	2006	NC Util Cm.		Pub. Service Co. of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	ISO82, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Co.	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co.-Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Co.	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Co.	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Co.	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Co.	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Co.	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Co.	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Co.	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Co.	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Co.	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Co. - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	Lancaster, City of – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	Il CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Co.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation
133.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Hanover, Borough of – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Co.	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Co.– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Co.	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Co.	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
165.	2013	DC PSC	Case 1103	PHI Service Co. – PEPCO	Depreciation
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Co.	Depreciation
167.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Co.	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Hanover, Borough of – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	Suez Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Co. – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Co. – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC		Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UT&C	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Oklahoma, Public Service Company of	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER17-___	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No.	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation

Rocky Mountain Power
Exhibit RMP___(JJS-2)
Docket No. 18-035-36
Witness: John J. Spanos

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John J. Spanos

Depreciation Study

September 11, 2018

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

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

September 11, 2018

Q. Please state your name and business address with PacifiCorp dba Rocky Mountain Power ("the Company").

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

QUALIFICATIONS

Q. Please describe your education and professional background.

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

Q. What are your current responsibilities with the Company?

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

Q. Have you testified in previous proceedings?

A. Yes. I have provided testimony in many dockets before the Public Service Commission of Utah ("Commission"). I have also provided testimony before the California, Idaho, Oregon, Washington, and Wyoming public utility commissions.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony supports the Company's request to implement depreciation rates from the 2018 Depreciation Study presented in this docket ("Depreciation Study"). Specifically, my testimony:

- Discusses the impact of the new depreciation rates and effective date on the annual depreciation expense allocated to Utah and provides support for the allocation of annual depreciation expense to Utah.
- Identifies and discusses state-specific items considered during the preparation of the Depreciation Study.
- Responds to reporting requirements from the Company's depreciation study approved in Docket No. 13-035-02 ("2013 depreciation study").

ALLOCATION OF THE DEPRECIATION STUDY

Q. What is the Utah-allocated effect on annual depreciation expense if the depreciation rates presented by Mr. John J. Spanos are adopted?

A. The Company allocated the annual depreciation expense using the 2017 Protocol allocation methodology that was approved in Docket No. 15-035-86 (the "2017 Protocol"). The adoption of the depreciation rates proposed in the Depreciation Study increase depreciation expense by approximately $100.1 million on a Utah basis. In addition, ending the excess reserve amortizations increase depreciation expense by $28.0 million on a Utah basis. The calculation of the Utah allocated depreciation increase is provided in attached Exhibit RMP___(SRM-1).

Q. What does the Company propose as the effective date for implementing the new depreciation rates?

A. The Company's accounting system maintains depreciation rates on a calendar year basis. Therefore, the Company proposes the new depreciation rates be made effective January 1, 2021.

Q. Does the 2017 Protocol allocation methodology expire before the proposed implementation for the new depreciation rates?

A. Yes. The 2017 Protocol is currently approved through December 31, 2019.

Q. Why is the Company proposing an effective date of January 1, 2021, after the current expiration of the 2017 Protocol allocation methodology?

A. The Company is actively working with parties in its service territories to develop and adopt a new allocation methodology commonly referred to as the Coal Life Evaluation and Realignment Plan ("CLEAR"). Although the timing of a formal approval is unknown, the Company believes an implementation date of January 1, 2021 would allow adequate time to resolve and gain approval of the new allocation methodology. Aligning the Depreciation Study with the anticipated approval of CLEAR would help maintain customer rate stability.

STATE-SPECIFIC ITEMS

Q. Please summarize the state-specific items you considered when preparing Depreciation Study testimony.

A. The primary state-specific issues I address in my Depreciation Study testimony are: (1) the expedited excess depreciation reserve amortizations, (2) the regulatory treatment of hydroelectric facilities on the Klamath River, and (3) the Company's proposed treatment of the Sustainable Transportation and Energy Plan ("STEP") regulatory liability.

Q. The approved stipulation to the 2013 depreciation study included expedited excess reserve amortizations. Please summarize the reasons those amortizations were established.

A. The primary reason excess reserves were established was to address the retirement of assets occurring outside of projected expectations and changes in lives and net salvage rates that had occurred. There were excess reserves for the Colstrip, Hunter, Gadsby Units 1-3, and Blundell steam production units. There were additional excess reserves for Utah, Idaho, and Wyoming distribution plant. Historically, any excess reserves are returned over the remaining life of the assets; however, as part of the 2013 depreciation study stipulation, parties agreed to expedite the return of these excess reserves over a shorter period.

Q. Over what period were the excess reserves to be returned to customers?

A. The excess reserve amortizations were to occur over the period between the effective date of the 2013 depreciation study and this filing.

Q. What is the Company proposing for excess reserve amortizations?

A. The Company proposes to end the excess reserve amortizations for Colstrip, Hunter, Gadsby Units 1-3, and Blundell steam production units. The Company also proposes to end the excess reserve amortizations in Utah, Idaho, and Wyoming for distribution plant. This results in a $4.9 million allocated impact for the elimination of the steam excess reserve amortizations and a $23.1 million impact for the elimination of the Utah distribution excess reserve amortizations. These excess reserve amortizations are provided in Exhibit RMP___(SRM-1).

Q. Please explain why hydroelectric plants on the Klamath River are not included in the Depreciation Study.

A. In the 2013 depreciation study, the Klamath River hydro facilities were calculated to be fully depreciated by December 31, 2019, before the proposed effective date of this Depreciation Study; thus, they were not included in the Depreciation Study.

Q. Does Utah assume different regulatory treatment of the Klamath facilities from what was calculated as part of the 2013 depreciation study?

A. Yes. In the Company's 2012 General Rate Case, Docket No. 11-035-200, stipulating parties agreed that the Company would depreciate the Klamath River hydro facilities through December 31, 2022. To effectuate this agreement, the Company makes a regulatory adjustment to remove the incremental depreciation associated with the 2019 Klamath facilities' depreciable life in Utah results of operations and other appropriate filings. The regulatory adjustment also removes Klamath relicensing costs and the associated amortization expense and reserve. Utah's allocated share of Klamath relicensing costs is included in a regulatory asset and amortized through December 31, 2022.

Q. Will the Company continue to make this adjustment for regulatory filings made in Utah?

A. Yes, the Company will continue to recognize the stipulated life of Klamath through a regulatory adjustment in the relevant filings in Utah.

Q. Does the STEP pilot program include any deferral that could be used to help offset the Utah-allocated share of depreciation expense as a result of the Depreciation Study?

A. Yes. The Company is currently deferring, on a monthly basis, to a regulatory liability the difference between the amount the Company collects for demand-side management programs ("DSM") and the 10-year amortization expense of DSM, plus carrying charges.

Q. What is the estimated regulatory liability balance associated with STEP funds on the proposed effective date of the Depreciation Study?

A. The Company estimates, based on projected load, the STEP regulatory liability balance will be approximately $188.9 million as of January 1, 2021. A projection of the STEP regulatory liability is provided as Exhibit RMP___(SRM-2).

Q. Would the Company support using the STEP regulatory liability to offset accelerated plant depreciation as part of this Depreciation Study?

A. Yes, the Company supports working with parties to develop a strategy for using the STEP regulatory liability to help offset any accelerated depreciation proposed as part of the Depreciation Study. Possible options include Cholla Unit 4, Colstrip, Craig, and Jim Bridger Units 1-2.

2013 DEPRECIATION STUDY REPORTING REQUIREMENTS

Q. Are there any additional exhibits you will be sponsoring as part of your direct testimony?

A. Yes, Paragraph 28 of the Commission-approved stipulation from the 2013 depreciation study stated:

> *"the Company will provide a section in the next depreciation study, for informational purposes only, listing the specific mining assets, reserve balances, and respective lives owned by its Wyoming mining subsidiary."*

This information is provided as Exhibit RMP___(SRM-3).

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission find that the depreciation rates presented by Mr. Spanos in the Depreciation Study based on projected December 31, 2020 balances are fair, just and reasonable depreciation rates. I further recommend that the Commission approve the Company's request to implement these depreciation rates in its accounts and records effective January 1, 2021.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(SRM-1)
Docket No. 18-035-36
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Utah Allocated

September 11, 2018

Rocky Mountain Power
Exhibit RMP___(SRM-1) Page 1 of 3
Docket No. 18-035-36
Witness: Steven R. McDougal

Rocky Mountain Power
Depreciation Rate Comparison - Plant Balances as of December 31, 2020

Description		AF	Plant-in-Service	Depreciation Rate		Total Company Depreciation			ALLOCATED
				EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	UT
Production Plant									
Steam Production		SG	7,224,199,492	3.40%	5.80%	245,923,367	419,112,432	173,189,065	75,344,448
Steam Production - Water Rights			35,638,063						
Hydro Production		SG	995,097,431	3.01%	3.06%	29,943,661	30,467,681	524,020	227,971
Other Production		SG	5,075,636,837	3.21%	4.02%	163,112,102	203,786,985	40,674,883	17,695,266
Other Production - Water Rights			32,709,325						
Total Production Plant			13,363,281,147						
Total Production Plant - Depreciable			13,294,933,760	3.30%	4.91%	438,979,130	653,367,098	214,387,968	93,267,685
Transmission Plant		SG	7,375,554,755	1.77%	1.90%	130,435,713	139,796,277	9,360,564	4,072,235
Distribution Plant									
Distribution		CA	280,326,706	2.67%	2.70%	7,472,463	7,570,061	97,598	-
Distribution		OR	2,243,678,194	2.52%	2.57%	56,492,130	57,702,243	1,210,113	-
Distribution		WA	526,113,490	2.76%	2.74%	14,526,469	14,411,610	(114,859)	-
Distribution		WY	783,969,878	2.97%	2.79%	23,248,951	21,881,003	(1,367,948)	-
Distribution		UT	3,160,310,244	2.62%	2.63%	82,950,370	83,098,150	147,780	147,780
Distribution		ID	386,446,632	2.71%	2.63%	10,453,988	10,163,756	(290,232)	-
Total Distribution			7,380,845,143	2.64%	2.64%	195,144,371	194,826,823	(317,548)	147,780
General Plant - Vehicles *									
General Plant - Vehicles	392.1 CA	CA	852,236	3.48%	8.63%	29,658	73,548	43,890	-
General Plant - Vehicles	392.1 CA	SG	304,035	3.48%	8.63%	10,580	26,238	15,658	6,812
General Plant - Vehicles	392.1 ID	ID	2,295,198	4.28%	8.73%	98,234	200,371	102,136	-
General Plant - Vehicles	392.1 ID	SG	768,932	4.28%	8.73%	32,910	67,128	34,217	14,886
General Plant - Vehicles	392.1 OR	OR	7,689,181	7.04%	6.43%	541,318	494,414	(46,904)	-
General Plant - Vehicles	392.1 OR	SG	857,171	7.04%	6.43%	60,345	55,116	(5,229)	(2,275)
General Plant - Vehicles	392.1 OR	SO	255,789	7.04%	6.43%	18,008	16,447	(1,560)	(673)
General Plant - Vehicles	392.1 OT	SG	409,796	2.53%	3.82%	10,368	15,654	5,286	2,300
General Plant - Vehicles	392.1 UT	SE	251,862	5.04%	8.92%	12,694	22,466	9,772	4,163
General Plant - Vehicles	392.1 UT	SG	3,051,700	5.04%	8.92%	153,806	272,212	118,406	51,512
General Plant - Vehicles	392.1 UT	SO	2,635,088	5.04%	8.92%	132,808	235,050	102,241	44,080
General Plant - Vehicles	392.1 UT	UT	10,010,742	5.04%	8.92%	504,541	892,958	388,417	388,417
General Plant - Vehicles	392.1 WA	SG	608,194	5.60%	2.90%	34,059	17,638	(16,421)	(7,144)
General Plant - Vehicles	392.1 WA	WA	1,022,424	5.60%	2.90%	57,256	29,650	(27,605)	-
General Plant - Vehicles	392.1 WY	SG	2,079,440	5.85%	8.78%	121,647	182,575	60,928	26,506
General Plant - Vehicles	392.1 WY	WY	2,585,714	5.85%	8.78%	151,264	227,026	75,761	-
General Plant - Vehicles	392.3 UT	SO	1,860,982	2.51%	6.23%	46,711	115,939	69,229	29,847
General Plant - Vehicles	392.5 CA	CA	793,720	4.49%	5.31%	35,638	42,147	6,509	-
General Plant - Vehicles	392.5 CA	SG	204,130	4.49%	5.31%	9,165	10,839	1,674	728
General Plant - Vehicles	392.5 ID	ID	4,350,829	4.34%	5.19%	188,826	225,808	36,982	-
General Plant - Vehicles	392.5 ID	SG	779,534	4.34%	5.19%	33,832	40,458	6,626	2,883
General Plant - Vehicles	392.5 OR	OR	11,812,885	5.48%	5.51%	647,346	650,890	3,544	-
General Plant - Vehicles	392.5 OR	SG	1,109,492	5.48%	5.51%	60,800	61,133	333	145
General Plant - Vehicles	392.5 OT	SG	236,400	2.10%	3.50%	4,964	8,274	3,310	1,440
General Plant - Vehicles	392.5 UT	SE	219,289	4.56%	6.38%	10,000	13,991	3,991	1,700
General Plant - Vehicles	392.5 UT	SG	3,608,320	4.56%	6.38%	164,539	230,211	65,671	28,570
General Plant - Vehicles	392.5 UT	SO	1,475,100	4.56%	6.38%	67,265	94,111	26,847	11,575
General Plant - Vehicles	392.5 UT	UT	18,540,989	4.56%	6.38%	845,469	1,182,915	337,446	337,446
General Plant - Vehicles	392.5 WA	SG	1,563,941	5.07%	3.43%	79,292	53,643	(25,649)	(11,158)
General Plant - Vehicles	392.5 WA	WA	3,133,469	5.07%	3.43%	158,867	107,478	(51,389)	-
General Plant - Vehicles	392.5 WY	SG	3,120,067	5.66%	6.86%	176,596	214,037	37,441	16,288
General Plant - Vehicles	392.5 WY	WY	5,012,276	5.66%	6.86%	283,695	343,842	60,147	-
General Plant - Vehicles	392.9 CA	CA	454,745	2.32%	2.68%	10,550	12,187	1,637	-
General Plant - Vehicles	392.9 CA	SG	13,637	2.32%	2.68%	316	365	49	21
General Plant - Vehicles	392.9 ID	SG	63,528	2.28%	2.44%	1,448	1,550	102	44

Rocky Mountain Power
Depreciation Rate Comparison - Plant Balances as of December 31, 2020

Description		AF	Plant-in-Service	Depreciation Rate		Total Company Depreciation			ALLOCATED
				EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	UT
General Plant - Vehicles	392.9 ID	ID	1,481,990	2.28%	2.44%	33,789	36,161	2,371	-
General Plant - Vehicles	392.9 OR	OR	3,355,388	2.44%	2.72%	81,871	91,267	9,395	-
General Plant - Vehicles	392.9 OR	SG	153,214	2.44%	2.72%	3,738	4,167	429	187
General Plant - Vehicles	392.9 OR	SO	3,491	2.44%	2.72%	85	95	10	4
General Plant - Vehicles	392.9 UT	SE	43,182	1.91%	3.47%	825	1,498	674	287
General Plant - Vehicles	392.9 UT	SG	1,306,628	1.91%	3.47%	24,957	45,340	20,383	8,868
General Plant - Vehicles	392.9 UT	SO	1,517,293	1.91%	3.47%	28,980	52,650	23,670	10,205
General Plant - Vehicles	392.9 UT	UT	5,800,349	1.91%	3.47%	110,787	201,272	90,485	90,485
General Plant - Vehicles	392.9 WA	SG	83,243	2.38%	2.29%	1,981	1,906	(75)	(33)
General Plant - Vehicles	392.9 WA	WA	620,650	2.38%	2.29%	14,771	14,213	(559)	-
General Plant - Vehicles	392.9 WY	SG	592,972	2.68%	3.07%	15,892	18,204	2,313	1,006
General Plant - Vehicles	392.9 WY	WY	3,220,759	2.68%	3.07%	86,316	98,877	12,561	-
General Plant - Vehicles	392.9 OT	SG	6,433	2.18%	1.65%	140	106	(34)	(15)
General Plant - Vehicles	396.3 CA	CA	1,447,080	7.20%	12.21%	104,190	176,689	72,499	-
General Plant - Vehicles	396.3 ID	SG	94,951	7.67%	11.95%	7,283	11,347	4,064	1,768
General Plant - Vehicles	396.3 ID	ID	2,987,665	7.67%	11.95%	229,154	357,026	127,872	-
General Plant - Vehicles	396.3 OR	OR	12,083,235	9.23%	9.31%	1,115,283	1,124,949	9,667	-
General Plant - Vehicles	396.3 OR	SG	82,388	9.23%	9.31%	7,604	7,670	66	29
General Plant - Vehicles	396.3 UT	SG	110,980	8.10%	10.55%	8,989	11,708	2,719	1,183
General Plant - Vehicles	396.3 UT	SO	1,450,283	8.10%	10.55%	117,473	153,005	35,532	15,319
General Plant - Vehicles	396.3 UT	UT	14,569,513	8.10%	10.55%	1,180,131	1,537,084	356,953	356,953
General Plant - Vehicles	396.3 WA	SG	76,764	5.66%	9.49%	4,345	7,285	2,940	1,279
General Plant - Vehicles	396.3 WA	WA	2,348,544	5.66%	9.49%	132,928	222,877	89,949	-
General Plant - Vehicles	396.3 WY	WY	4,408,344	8.47%	14.89%	373,387	656,402	283,016	-
General Plant - Vehicles	396.7 CA	CA	2,265,611	4.98%	5.59%	112,827	126,648	13,820	-
General Plant - Vehicles	396.7 ID	ID	6,717,318	3.73%	5.39%	250,556	362,063	111,507	-
General Plant - Vehicles	396.7 ID	SG	1,069,121	3.73%	5.39%	39,878	57,626	17,747	7,721
General Plant - Vehicles	396.7 OR	OR	22,854,375	5.14%	5.20%	1,174,715	1,188,428	13,713	-
General Plant - Vehicles	396.7 OR	SG	1,524,457	5.14%	5.20%	78,357	79,272	915	398
General Plant - Vehicles	396.7 OT	SG	1,943,963	1.86%	2.66%	36,158	51,709	15,552	6,766
General Plant - Vehicles	396.7 UT	SE	382,959	5.36%	6.09%	20,527	23,322	2,796	1,191
General Plant - Vehicles	396.7 UT	SG	13,090,861	5.36%	6.09%	701,670	797,233	95,563	41,574
General Plant - Vehicles	396.7 UT	SO	3,825,432	5.36%	6.09%	205,043	232,969	27,926	12,040
General Plant - Vehicles	396.7 UT	UT	35,912,226	5.36%	6.09%	1,924,895	2,187,055	262,159	262,159
General Plant - Vehicles	396.7 WA	SG	465,312	6.03%	3.93%	28,058	18,287	(9,772)	(4,251)
General Plant - Vehicles	396.7 WA	WA	5,846,223	6.03%	3.93%	352,527	229,757	(122,771)	-
General Plant - Vehicles	396.7 WY	SG	24,392,855	4.86%	5.80%	1,185,493	1,414,786	229,293	99,752
General Plant - Vehicles	396.7 WY	WY	14,896,522	4.86%	5.80%	723,971	863,998	140,027	-
Total General Plant - Vehicles*			287,063,409	5.33%	6.52%	15,314,391	18,703,259	3,388,868	1,862,988

Rocky Mountain Power
Depreciation Rate Comparison - Plant Balances as of December 31, 2020

Description		AF	Plant-in-Service	Depreciation Rate		Total Company Depreciation			ALLOCATED
				EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	UT
General Plant - All Other									
General Plant - All Other	389.2 ID	ID	4,646	1.17%	1.70%	54	79	25	-
General Plant - All Other	389.2 UT	SG	1,183	2.03%	2.05%	24	24	0	0
General Plant - All Other	389.2 UT	UT	80,996	2.03%	2.05%	1,644	1,660	16	16
General Plant - All Other	389.2 WY	WY	74,246	1.98%	1.88%	1,470	1,396	(74)	-
General Plant - All Other	390 CA	CA	3,012,931	1.71%	1.99%	51,520	59,997	8,477	-
General Plant - All Other	390 CA	SO	456,255	1.71%	1.99%	7,802	9,079	1,278	551
General Plant - All Other	390 ID	ID	12,477,686	1.65%	1.84%	205,883	229,225	23,342	-
General Plant - All Other	390 ID	SG	1,446,832	1.65%	1.84%	23,873	26,622	2,749	1,196
General Plant - All Other	390 ID	SO	779,213	1.65%	1.84%	12,857	14,338	1,481	638
General Plant - All Other	390 OR	OR	33,518,026	1.86%	2.08%	623,435	702,170	78,735	-
General Plant - All Other	390 OR	SG	2,963,511	1.86%	2.08%	55,121	61,641	6,520	2,836
General Plant - All Other	390 OR	SO	49,771,365	1.86%	2.08%	925,747	1,035,244	109,497	47,209
General Plant - All Other	390 OT	SG	363,676	1.51%	1.76%	5,492	6,401	909	396
General Plant - All Other	390 UT	CN	8,374,998	1.53%	2.55%	128,137	213,562	85,425	40,341
General Plant - All Other	390 UT	SG	2,387,110	1.53%	2.55%	36,523	60,871	24,349	10,593
General Plant - All Other	390 UT	SO	40,099,508	1.53%	2.55%	613,522	1,022,537	409,015	176,343
General Plant - All Other	390 UT	UT	45,382,211	1.53%	2.55%	694,348	1,155,442	461,094	461,094
General Plant - All Other	390 UT	SE	1,041,182	1.53%	2.55%	15,930	26,550	10,620	4,524
General Plant - All Other	390 WA	SG	92,763	2.52%	2.08%	2,338	1,929	(408)	(178)
General Plant - All Other	390 WA	SO	1,488,037	2.52%	2.08%	37,499	30,951	(6,547)	(2,823)
General Plant - All Other	390 WA	WA	11,467,860	2.52%	2.08%	288,991	239,453	(49,538)	-
General Plant - All Other	390 WY	SG	860,033	1.95%	2.55%	16,771	21,931	5,160	2,245
General Plant - All Other	390 WY	SO	132,386	1.95%	2.55%	2,582	3,376	794	342
General Plant - All Other	390 WY	WY	17,893,960	1.95%	2.55%	348,933	456,770	107,837	-
Total General Plant - All Other			234,170,613	1.75%	2.30%	4,100,495	5,381,250	1,280,755	745,322
Total General Plant			521,234,022	3.72%	4.62%	19,414,887	24,084,509	4,669,623	2,608,310
Total Company - Depreciable Plant			**28,572,567,679**	**2.74%**	**3.54%**	**783,974,101**	**1,012,074,708**	**228,100,607**	**100,096,010**

COLSTRIP RESERVE AMORTIZATION	SG	(2,293,038)	-	2,293,038	997,567
HUNTER RESERVE AMORTIZATION	SG	(5,927,184)	-	5,927,184	2,578,572
GADSBY RESERVE AMORTIZATION	SG	(2,341,500)	-	2,341,500	1,018,650
BLUNDELL RESERVE AMORTIZATION	SG	(785,202)	-	785,202	341,596
WYOMING - DISTRIBUTION RESERVE AMORTIZATION	WY	(2,077,204)	-	2,077,204	-
UTAH - DISTRIBUTION RESERVE AMORTIZATION	UT	(23,109,549)	-	23,109,549	23,109,549
IDAHO - DISTRIBUTION RESERVE AMORTIZATION	ID	(2,508,698)	-	2,508,698	-

* For regulatory purposes, vehicle depreciation is re-classified as operations and maintenance expense.

Rocky Mountain Power
Exhibit RMP___(SRM-2)
Docket No. 18-035-36
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Estimated STEP Deferral and Amortization Table

September 11, 2018

Rocky Mountain Power
Exhibit RMP___(SRM-2) Page 1 of 1
Docket No. 18-035-36
Witness: Steven R. McDougal

Rocky Mountain Power
Estimated STEP Deferral and Amortization Table
State of Utah
$ - Thousands

Carrying Charge Rate[2]
9.21%

2018

	Jan Actuals	Feb Actuals	Mar Actuals	Apr Actuals	May Actuals	Jun Actuals	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
Regulatory Asset													
Beginning Regulatory Asset Balance	55,393	59,022	61,651	64,341	67,056	70,684	74,989	78,885	82,744	87,071	90,855	96,791	55,393
Expenditures	4,091	3,119	3,211	3,268	4,209	4,920	4,548	4,548	5,057	4,553	6,753	5,160	53,435
(Expense Amortization)	(461)	(490)	(521)	(552)	(582)	(615)	(651)	(689)	(729)	(769)	(816)	(866)	(7,743)
Ending Regultory Asset Balance	59,022	61,651	64,341	67,056	70,684	74,989	78,885	82,744	87,071	90,855	96,791	101,085	101,085
Regulatory Liability													
Beginning Regulatory Liability Balance	(51,024)	(53,060)	(57,236)	(61,551)	(65,957)	(70,205)	(75,765)	(82,839)	(89,554)	(95,001)	(99,215)	(103,422)	(51,024)
(DSM Collections)	(2,516)	(4,661)	(4,833)	(4,945)	(4,810)	(6,141)	(7,707)	(7,362)	(6,120)	(4,921)	(4,966)	(5,473)	(64,458)
Expense Amortization	461	490	521	552	582	615	651	689	729	769	816	866	7,743
Net Carrying Charge[1]	19	(5)	(3)	(13)	(20)	(33)	(18)	(41)	(56)	(62)	(57)	(52)	(343)
Ending Regulatory Liability Balance	(53,060)	(57,236)	(61,551)	(65,957)	(70,205)	(75,765)	(82,839)	(89,554)	(95,001)	(99,215)	(103,422)	(108,081)	(108,081)

2019

	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
Regulatory Asset													
Beginning Regulatory Asset Balance	101,085	104,685	108,214	112,445	116,399	119,904	123,604	127,129	130,615	134,197	137,506	143,711	101,085
Expenditures	4,506	4,473	5,215	4,981	4,571	4,805	4,670	4,670	4,805	4,571	7,518	4,667	59,454
(Expense Amortization)	(906)	(944)	(984)	(1,027)	(1,066)	(1,105)	(1,145)	(1,184)	(1,223)	(1,262)	(1,313)	(1,364)	(13,523)
Ending Regultory Asset Balance	104,685	108,214	112,445	116,399	119,904	123,604	127,129	130,615	134,197	137,506	143,711	147,015	147,015
Regulatory Liability													
Beginning Regulatory Liability Balance	(108,081)	(112,313)	(115,919)	(119,581)	(123,004)	(126,661)	(130,708)	(135,650)	(140,339)	(144,033)	(147,459)	(150,923)	(108,081)
(DSM Collections)	(5,082)	(4,492)	(4,589)	(4,398)	(4,672)	(5,099)	(6,027)	(5,803)	(4,843)	(4,612)	(4,711)	(5,126)	(59,454)
Expense Amortization	906	944	984	1,027	1,066	1,105	1,145	1,184	1,223	1,262	1,313	1,364	13,523
Net Carrying Charge[1]	(56)	(59)	(57)	(53)	(51)	(53)	(60)	(70)	(75)	(76)	(66)	(57)	(730)
Ending Regulatory Liability Balance	(112,313)	(115,919)	(119,581)	(123,004)	(126,661)	(130,708)	(135,650)	(140,339)	(144,033)	(147,459)	(150,923)	(154,742)	(154,742)

2020

	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
Regulatory Asset													
Beginning Regulatory Asset Balance	147,015	150,249	153,435	157,349	160,986	164,148	167,502	170,686	173,828	177,061	180,020	186,001	147,015
Expenditures	4,636	4,627	5,397	5,164	4,730	4,963	4,832	4,832	4,963	4,730	7,804	4,819	61,495
(Expense Amortization)	(1,402)	(1,441)	(1,483)	(1,527)	(1,568)	(1,608)	(1,649)	(1,689)	(1,730)	(1,771)	(1,823)	(1,875)	(19,566)
Ending Regultory Asset Balance	150,249	153,435	157,349	160,986	164,148	167,502	170,686	173,828	177,061	180,020	186,001	188,945	188,945
Regulatory Liability													
Beginning Regulatory Liability Balance	(154,742)	(157,943)	(160,691)	(163,355)	(165,806)	(168,461)	(171,459)	(175,246)	(178,794)	(181,440)	(183,829)	(186,236)	(154,742)
(DSM Collections)	(4,544)	(4,131)	(4,097)	(3,936)	(4,188)	(4,574)	(5,403)	(5,201)	(4,341)	(4,128)	(4,215)	(4,583)	(53,341)
Expense Amortization	1,402	1,441	1,483	1,527	1,568	1,608	1,649	1,689	1,730	1,771	1,823	1,875	19,566
Net Carrying Charge[1]	(59)	(57)	(51)	(41)	(35)	(32)	(33)	(36)	(36)	(31)	(15)	(1)	(427)
Ending Regulatory Liability Balance	(157,943)	(160,691)	(163,355)	(165,806)	(168,461)	(171,459)	(175,246)	(178,794)	(181,440)	(183,829)	(186,236)	(188,945)	**(188,945)**

Footnotes:
1 - Includes net carrying charge of regulatory asset and regulatory liability
2 - Docket No. 13-035-184 Pre tax weighted average cost of capital

Rocky Mountain Power
Exhibit RMP___(SRM-3)
Docket No. 18-035-36
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Bridger Coal Company Balances

September 11, 2018

Bridger Coal Company
Property, Plant and Equipment - 100%
as of December 31, 2017

General Ledger Account	Account Description	Original Cost	Depreciation Reserve	Net Book Value	Average Service Life	Average Age
Location Code 03 - Surface Mine						
1605	Land Improvements	$ 299,546	$ 244,942	$ 54,604	35.5	21.0
1610	Mine Development	$ 16,948,682	$ 11,813,551	$ 5,135,131	28.9	16.9
1615	Buildings & Improvements	$ 12,517,845	$ 7,887,893	$ 4,629,952	23.5	9.5
1620	Allowance for Funds Used During Construction	$ 263,360	$ 189,476	$ 73,884	46.5	26.5
1625	Surface Roads (haulage / access)	$ 6,671,774	$ 5,145,000	$ 1,526,774	47.6	27.6
1630	Mining Equipment	$ 8,005,477	$ 5,333,340	$ 2,672,137	24.5	17.5
1635	Heavy Equipment-Vehicles	$ 140,314,588	$ 94,707,410	$ 45,607,178	9.6	9.8
1640	Office Furniture & Equipment	$ 10,550	$ 10,550	$ -	5.0	5.6
1645	Computer Hardware & Software	$ 48,896	$ 25,532	$ 23,364	4.8	2.6
1650	Other Equipment	$ 2,248,470	$ 1,525,535	$ 722,935	7.2	7.4
1699	Mineral Rights / Coal Reserve Leases	$ 1,104,601	$ 15,402	$ 1,089,200	tons extracted	
		$ 188,433,790	**$ 126,898,631**	**$ 61,535,159**		
Location Code 06 - Underground Mine						
1605	Land Improvements	$ 11,908,130	$ 7,940,052	$ 3,968,078	13.6	9.5
1610	Mine Development	$ 3,789,975	$ 1,883,382	$ 1,906,593	5.84	2.71
1615	Buildings & Improvements	$ 28,027,676	$ 16,764,924	$ 11,262,752	9.97	6.96
1620	Allowance for Funds Used During Construction	$ 147,040	$ 99,965	$ 47,075	16.05	12.02
1625	Surface Roads (haulage / access)	$ 8,699,099	$ 6,307,990	$ 2,391,110	20.79	16.54
1630	Mining Equipment	$ 167,305,312	$ 136,678,366	$ 30,626,947	6.58	7.24
1630	Longwall Mining - Shields / Roof Supports	$ 33,668,116	$ 19,544,804	$ 14,123,312	units of production	
1635	Heavy Equipment-Vehicles	$ 11,244,447	$ 9,580,598	$ 1,663,849	7.03	9.25
1640	Office Furniture & Equipment	$ 105,342	$ 75,169	$ 30,172	7.88	4.92
1645	Computer Hardware & Software	$ 260,857	$ 191,833	$ 69,024	5.00	6.89
1650	Other Equipment	$ 8,116,312	$ 6,210,631	$ 1,905,681	6.01	5.37
1699	Mineral Rights / Coal Reserve Leases	$ 14,415,970	$ 6,808,591	$ 7,607,380	tons extracted	
		$ 287,688,278	**$ 212,086,304**	**$ 75,601,974**		
Location Code 09 - Administrative/Common Facilities						
1600	Land	$ 6,211	$ -	$ 6,211	n/a	n/a
1615	Buildings & Improvements	$ 5,285,585	$ 3,752,948	$ 1,532,637	24.5	19.3
1630	Mining Equipment	$ 549,007	$ 334,793	$ 214,214	42.5	29.3
1635	Heavy Equipment-Vehicles	$ 2,073	$ 1,330	$ 743	10.0	6.1
1640	Office Furniture & Equipment	$ 44,596	$ 38,299	$ 6,297	7.9	9.6
1645	Computer Hardware & Software	$ 3,773,629	$ 3,454,106	$ 319,523	5.0	4.9
1650	Other Equipment	$ 752,692	$ 635,139	$ 117,553	8.7	9.3
		$ 10,413,792	**$ 8,216,616**	**$ 2,197,176**		
Total Bridger Coal Company						
1600	Land	$ 6,211	$ -	$ 6,211		
1605	Land Improvements	$ 12,207,676	$ 8,184,994	$ 4,022,682		
1610	Mine Development	$ 20,738,657	$ 13,696,933	$ 7,041,724		
1615	Buildings & Improvements	$ 45,831,106	$ 28,405,765	$ 17,425,341		
1620	AFUDC	$ 410,400	$ 289,441	$ 120,959		
1625	Surface Roads (haulage / access)	$ 15,370,874	$ 11,452,990	$ 3,917,884		
1630	Mining Equipment	$ 175,859,796	$ 142,346,499	$ 33,513,298		
1630	Longwall Mining - Shields / Roof Supports	$ 33,668,116	$ 19,544,804	$ 14,123,312		
1635	Heavy Equipment-Vehicles	$ 151,561,108	$ 104,289,338	$ 47,271,770		
1640	Office Furniture & Equipment	$ 160,488	$ 124,019	$ 36,469		
1645	Computer Hardware & Software	$ 4,083,382	$ 3,671,471	$ 411,911		
1650	Other Equipment	$ 11,117,474	$ 8,371,306	$ 2,746,169		
1699	Mineral Rights / Coal Reserve Leases	$ 15,520,572	$ 6,823,992	$ 8,696,580		
		$ 486,535,860	**$ 347,201,551**	**$ 139,334,309**		

Amounts shown are 100% (PacifiCorp share is two-thirds)
Life of mine - Surface Mine-December 2037 / Underground Mine-March 2022
Depreciation Expense Methology - all assets are depreciated using the "straight-line" method with the following exceptions
1) Underground Mine - Longwall Mining - Shields / Roof Support - uses "units of production / cycles"
2) Mineral Rights / Coal Reserves both mines use "units of production / tons extracted"

Rocky Mountain Power
Docket No. 18-035-36
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Chad A. Teply

September 11, 2018

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

A. My name is Chad A. Teply. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah. My position is Senior Vice President of Strategy and Development for Rocky Mountain Power (the "Company"), a division of PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I joined MidAmerican Energy Company (a Berkshire Hathaway Energy affiliate company) in November 1999, and held positions of increasing responsibility within the generation organization. In April 2008, I moved to Northern Natural Gas Company (a Berkshire Hathaway Energy affiliate company) as Senior Director of Engineering. I joined PacifiCorp in February 2009. In my current role as Senior Vice President of Strategy and Development, my responsibilities encompass strategic planning, regulatory support, stakeholder engagement, development and execution of major generation resource additions, major environmental compliance projects, and major transmission projects.

Q. Please explain the responsibilities of the resource development staff within your organization.

A. My resource development staff is responsible for developing generation resource options that the Company can potentially implement, if determined to be least cost on a risk-adjusted basis. Resource development staff is also responsible for developing and providing performance and cost information related to supply-side resource options used in the Company's integrated resource planning ("IRP") process, and maintaining data on existing resource capacities, performance, and costs. Resource development staff also maintains cost and performance information on current and emerging environmental regulations that may affect the operation of the Company's thermal generating assets.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony:

- Describes the process used by the Company to develop estimated economic lives for the thermal generation resources that are incorporated into the Company's new depreciation study submitted with Mr. John J. Spanos's testimony as Exhibit RMP___(JJS-2) (the "Depreciation Study") in this filing.
- Provides an overview of the recommended changes to the depreciable lives of the Company's thermal generation resources based on the Company's assessment of major factors and changes since the 2013 depreciation study.
- Presents the Company's recommendations on decommissioning costs. I explain how these costs were developed from updated studies and are now applied on a plant-by-plant basis.

DEVELOPMENT OF DEPRECIABLE PLANT LIFE

Q. Why is it necessary to estimate the economic life of a generation asset to develop depreciation rates?

A. One component of the Company's cost of service is the recovery of capital investment. This recovery is accomplished through depreciation expense over the life of each resource. Because depreciation rates spread a certain amount of cost over a certain period of time, it is necessary to have a reasonable estimate of the economic life of a resource at the time it is placed into service to properly calculate its depreciation expense. The estimated plant economic life of a generation asset is the period of time that begins when the asset is placed in service and starts generating electricity, and ends when the asset is removed from service. In other words, it is the period of time during which customers benefit from the asset.

Q. Is a plant's estimated economic life permanently set when the plant is placed into service?

A. No. For depreciation purposes, all generation asset economic lives are estimates that may be adjusted over time as circumstances warrant. The Company reevaluates its economic life estimates each time it performs a depreciation study. In this case, the Company provided estimated generation plant depreciable lives information to Mr. Spanos for his use in preparing the Depreciation Study.

Q. Are you also providing the Company's estimated thermal generation plant economic lives information for this docket?

A. Yes. Exhibit RMP___(CAT-1) accompanying my testimony contains a complete list of PacifiCorp's thermal generation plants and their recommended depreciable lives.

DEPRECIABLE LIVES FOR THERMAL GENERATION RESOURCES

Q. Please describe the process the Company used to assess the depreciable lives of its thermal generation resources.

A. The Company began with the estimated retirement years from the 2013 depreciation study. The Company then considered capital expenditures, impacts to ongoing operating and maintenance expenses, and the potential for accelerated timelines for resource planning decisions. These factors were considered in the following context: (1) major equipment condition; (2) fuel cost and availability; (3) environmental compliance obligations; and (4) policy and market drivers.

Based on the unique circumstances that affect individual units at a given plant, the Company also modified its current practice of using a single retirement year for a plant. Instead of using a single retirement year for a plant, the Company proposes to use the depreciable lives of the individual coal-fired generation units at each plant.

Q. Please explain how major equipment condition can affect the depreciable life of a thermal generation resource.

A. Major equipment condition is influenced by the planned outage schedule. Thermal resources, including the coal-fired, gas-fired, and geothermal resources involving the production and transport of steam, normally undergo overhauls on four-year cycles, eight-year cycles, or 12-year cycles. The Company establishes outage schedules for coal-fired resources based on its industry operating experience. It establishes overhaul schedules for gas-fired combustion turbine-based resources based on the number of operating hours and starts of the units and the recommendations of the original equipment manufacturer. Major equipment or component replacements, such as replacing cooling towers, condenser re-tubing, replacing turbine components, re-winding generators, or replacing steam generator components, may be required at these overhaul milestones. These periodic milestone replacements are important to the ongoing operation of the resource. If capital investment is required, the resource may no longer be economic to operate, depending on the level of investment and expected remaining life.

Q. Please explain how fuel cost and availability can affect the depreciable life of a thermal generation resource.

A. Fuel cost, fuel availability, and, to an extent, fuel quality can influence the economic life of a thermal generation resource. Significant changes in the cost, availability, or quality of the resource's fuel supply can drive major capital expenditures or result in increased run-rate costs that could make the resource uneconomic to operate. Issues at captive mines that serve the Company's resources are likely to have more direct impacts, depending upon the availability of alternative competitive market suppliers. Switching to a different fuel source, and procuring and delivery of this alternate fuel, could require major capital expenditures, or result in increased run-rate fuel costs, which can also drive economic-life decisions for individual resources.

Q. Please explain how environmental regulations can affect the depreciable life of a thermal generation asset.

A. Existing, evolving, and emerging air emissions standards, water intake and effluent discharge standards, and solid waste regulations may impact the economics of operating an asset. New regulations or changes to existing air, water, or solid waste regulations influence the timing of capital expenditures for compliance and the subsequent operating and maintenance costs. Capital expenditures for compliance with environmental regulations include air pollution controls, water intake infrastructure modifications, discharge constraints, cooling system changes, and new or upgraded coal combustion waste infrastructure to transport and store bottom ash, fly ash, and scrubber waste. Capital expenditures, once made, must be recovered over the remaining life of the asset. If a major capital investment is required to meet a new environmental standard but it is not feasible or economic to recover the investment over the remaining life of the asset, this could result in the early retirement of the asset.

Q. Have any significant new environmental regulations or compliance obligations been implemented since the Company's last depreciation study that could affect thermal generation resource depreciable lives?

A. Yes. Several environmental regulations and compliance obligations have been implemented since the Company's 2013 depreciation study. First, the United States Environmental Protection Agency ("EPA") and the states of Arizona, Colorado, Utah, and Wyoming have continued to implement their Regional Haze state and federal implementation plans. Since 2013, the Company has taken steps to install emissions control equipment, and negotiate alternative compliance outcomes for certain units[1], and is currently supporting ongoing requests for reconsideration of and, in some instances, litigation over, other implementation plan requirements[2]. These efforts and outcomes affect several of the Company's wholly-owned or partially-owned generation resources. The Company generally assesses its compliance obligations and alternatives as part of its regular IRP filings, the most recent of which are the 2017 IRP and the 2017 IRP Update, which are available on the Company's website. Detailed discussion of the Company's completed compliance projects and upcoming compliance decisions

[1] In 2014, installation of new low_NOx burners, a scrubber upgrade, and new baghouse at Hunter Unit 1. In 2015, installation of selective catalytic reduction ("SCR") systems at Jim Bridger Unit 3 and Hayden Unit 1. In 2016, installation of SCR systems at Jim Bridger Unit 4 and Hayden Unit 2. Also in 2016, an SCR alternative for Dave Johnston Unit 3 was approved by EPA. In 2017, an SCR system was installed at Craig Unit 2 and an SCR alternative for Cholla Unit 4 was approved by EPA. In 2018, an SCR alternative for Craig Unit 1 was approved by EPA. The Company is in discussions with the Wyoming Department of Environmental Quality and the EPA regarding an SCR alternative for Jim Bridger Units 1 and 2.

[2] The EPA is currently in the process of reconsideration of Utah Regional Haze compliance requirements and litigation of EPA's Regional Haze federal implementation plan requirements for Hunter Units 1 and 2 and Huntington Units 1 and 2. Litigation of EPA's Regional Haze federal implementation plan requirements for Wyodak and Naughton Units 1 and 2 is also still on-going.

is included in the referenced IRPs and reflected in the proposed depreciable lives for individual units discussed further in this filing.

Second, since 2013 the EPA has initially proposed, partially litigated, rescinded, and now proposed replacement of the Clean Power Plan focused on reduction of carbon dioxide (“CO_2”) emissions from the United States energy sector. While no specific greenhouse gas compliance expenditures were pursued in response to the Clean Power Plan, the Company’s IRP continues to incorporate assumptions and sensitivities regarding potential greenhouse gas policy outcomes.

Finally, since 2013 the EPA has proposed, partially litigated, and modified its Coal Combustion Residual regulations as part of the Resource Conservation and Reclamation Act, as well as its Effluent Limitation Guidelines as part of the Clean Water Act. These regulations require utilities with coal-fired generation facilities to meet certain compliance obligations for ash and coal residue handling, infrastructure, and storage facilities, as well as their process wastewater streams. Although the Company’s Depreciation Study considers these environmental regulations, it is not significantly impacted at this time by anticipated compliance obligations in these areas.

Q. Did the Company make capital expenditures for environmental compliance with the intent to extend the resource lives of thermal generation resources?

A. No. While the Company has made capital additions since 2013 on a number of its coal-fueled generation assets to comply with environmental regulations, the Company’s analysis and justification of these investments assumed that the plant lives would not be extended. Rather, the Company assumed the compliance expenditures would allow the individual unit to operate through their currently-approved depreciable lives.

Q. What emerging policy and market drivers affect the estimated depreciable lives of generation resources?

A. Since the Company's 2013 depreciation study, policymakers in the Company's service territory have continued to propose, consider, and promulgate state-specific policies affecting the Company's generation resource planning. The Company's long-term resource planning and estimated depreciable lives of thermal generation resources are influenced by a variety of policy and market drivers, including wholesale power and natural gas prices, public policy and regulatory initiatives, and events and trends affecting the economy.

One notable public policy example is Oregon Senate Bill 1547-B, which was signed into law by the governor of Oregon on March 8, 2016. Senate Bill 1547-B, the Clean Electricity and Coal Transition Plan, extends and expands the Oregon Renewable Portfolio Standard requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources be eliminated from Oregon's allocation of electricity by January 1, 2030.

This and other planning environment drivers are discussed in detail in Chapter 3 of the Company's 2017 IRP, which is publicly available on the Company's website.

Q. Based on these considerations, what major changes does the Company propose to the depreciable lives of its thermal generation resources?

A. The Company is proposing several changes to its thermal generation depreciable lives based on its analysis of the various factors described earlier in my testimony.

First, the Company recommends accelerating the depreciable life of Cholla Unit 4 from 2042 to 2025 to align with the unit's approved Regional Haze Rule compliance obligation timeline. This compliance date was established in settlement discussions between the facility joint owners, state and federal agencies, and stakeholders in 2015 and 2016; approvals were received through subsequent state and federal agency public processes in 2017 and 2018. Cholla Unit 4 will be 44 years old in 2025.

The second recommended change is to accelerate the depreciable lives of Jim Bridger Units 1 and 2 from 2037 to 2028 and 2032, respectively, to align with the Company's 2017 IRP preferred portfolio. The 2017 IRP preferred portfolio reflects the Company's analysis of potential alternate Regional Haze Rule compliance outcomes for Units 1 and 2 that result in a least-cost, least-risk outcome for customers when compared to installation of major emissions control equipment retrofits in 2021 and 2022, as currently required in the Wyoming Regional Haze state implementation plan, as approved by EPA. Approval of these accelerated depreciation dates facilitates alternate Regional Haze compliance decision-making for Units 1 and 2. The Company has not yet received state or federal agency approvals of this alternate Regional Haze compliance outcome for Jim Bridger Units 1 and 2, but has engaged the agencies in discussions regarding potential alternative compliance. Jim Bridger Unit 1 will be 54 years old in 2028, and Jim Bridger Unit 2 will be 57 years old in 2032.

The third recommended change is to accelerate the depreciable life of Craig Unit 1 from 2034 to 2025 to align with its approved Regional Haze Rule compliance obligation timeline. This compliance date was established in settlement discussions between the facility joint owners, state and federal agencies, and stakeholders in 2015 and 2016; approvals were received through subsequent state and federal agency public processes in 2017 and 2018. Craig Unit 1 will be 45 years old in 2025.

The fourth recommended change is to accelerate the depreciable life of Craig Unit 2 from 2034 to 2026 to facilitate least-cost, least-risk analysis, decision making, and planning as Craig Unit 1 approaches retirement in 2025, as currently expected, and Craig Unit 2 economics and joint owner business planning decisions are made in the interim. The Craig Unit 2 joint owners and stakeholders have not approved accelerated retirement of the unit, nor has formal engagement on that potential outcome been initiated. Craig Unit 2 will be 47 years old in 2026.

The fifth recommended change is to accelerate the depreciable life of Colstrip Units 3 and 4 from 2046 to 2027 to facilitate least-cost, least-risk analysis, decision making, and planning as announced retirements of Colstrip Units 1 and 2 (non-Company resources) in 2022 approach, and Colstrip Units 3 and 4 economics and joint owner business planning decisions are made in the interim. The Colstrip Units 3 and 4 joint owners and stakeholders have not approved accelerated retirement of those units, nor has formal engagement on that potential outcome been initiated. However, certain joint owners (Avista – 15 percent, and Puget Sound Energy – 25 percent) have reached agreements with their respective regulators to establish 2027 as the new depreciable life for the units. Colstrip Units 3 and 4 will be 43 years old and 41 years old, respectively, in 2027.

For the Company's remaining thermal generation resources, I recommend to maintain the current depreciable lives consistent with prior depreciation studies.

Q. Has the Company changed the depreciable lives for its natural gas-fired simple-cycle combustion turbine resources?

A. No. The Company is not recommending any change to the depreciable lives of its simple-cycle natural gas combustion turbines. The simple-cycle combustion turbines in the Company's fleet are aero-derivative combustion turbines and operate when economic and/or when required for system reliability purposes. Operating profiles and assumptions pertaining to outage schedules and equipment longevity for these units have not materially changed. Moreover, fuel availability for the simple-cycle gas combustion turbine units has not changed. The original equipment manufacturer's 30-year useful life recommendation has not changed and remains consistent with the 2013 depreciation study.

Q. Has the Company changed the depreciable lives for its natural gas-fired combined-cycle combustion turbine resources?

A. No. The Company is not recommending any change to the depreciable lives of its combined-cycle gas combustion turbines. These plants operate when economic and/or when required for system reliability purposes. Since the 2013 depreciation study, the operating profiles and assumptions pertaining to outage schedules and equipment longevity for these units have not materially changed. Moreover, fuel availability for the combined-cycle gas combustion turbine resources has not changed. The original equipment manufacturer's 40-year useful life recommendation has not changed and remains consistent with the 2013 depreciation study. However, it is feasible with continued maintenance investment and technology advancements that these facilities could operate economically beyond the original equipment manufacturer's 40-year useful life recommendation.

DECOMMISSIONING/DEMOLITION COSTS

Q. Is the Company proposing changes to decommissioning costs in the Depreciation Study for the Company's thermal generation resources?

A. Yes. The Company performed updated decommissioning cost studies in the 2014 to 2016 timeframe on a selection of its thermal generation resources considered reasonable proxy resources for extrapolation across the fleet. These studies were used as the primary basis for the decommissioning costs in this filing, with certain updates made to reflect plant-specific attributes and updated commodity and scrap market costs. Based on these studies, the Company proposes to replace the previously approved decommissioning cost of $40 per kilowatt for all coal-fueled plants with the plant-by-plant decommissioning costs provided in Exhibit RMP___(CAT-2). The Company also proposes to replace the previously approved decommissioning cost of $15 per kilowatt for all natural gas-fueled plants with an updated decommissioning cost estimate of $10 per kilowatt.

The Company hired a third-party engineering firm to complete the baseline decommissioning studies. The decommissioning costs in Exhibit RMP___(CAT-2), include plant demolition, ash pile and ash pond abatement and closure, asbestos and other hazardous materials abatement and remediation, and final site cleanup and restoration as applicable to each plant.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(CAT-1)
Docket No. 18-035-36
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

PacifiCorp Estimated Plant Retirement Lives – Steam and Gas

September 11, 2018

PacifiCorp Estimated Plant Retirement Lives - Steam and Gas

	Commercial Operations Date	Current Depreciable Life Span (Years)	Current End of Depreciation Year	Recommended Depreciable Life Span (Years)	Recommended End of Depreciation Year	Life Span Difference: Recommended - Current (Years)
Steam						
Cholla-4	1981	61	2042	44	2025	(17)
Colstrip-3	1984	62	2046	43	2027	(19)
Colstrip-4	1986	60	2046	41	2027	(19)
Craig-1	1980	54	2034	45	2025	(9)
Craig-2	1979	55	2034	47	2026	(8)
Dave Johnston-1	1959	68	2027	68	2027	—
Dave Johnston-2	1960	67	2027	67	2027	—
Dave Johnston-3	1964	63	2027	63	2027	—
Dave Johnston-4	1972	55	2027	55	2027	—
Hayden-1	1965	65	2030	65	2030	—
Hayden-2	1976	54	2030	54	2030	—
Hunter-1	1978	64	2042	64	2042	—
Hunter-2	1980	62	2042	62	2042	—
Hunter-3	1983	59	2042	59	2042	—
Huntington-1	1977	59	2036	59	2036	—
Huntington-2	1974	62	2036	62	2036	—
Jim Bridger-1	1974	63	2037	54	2028	(9)
Jim Bridger-2	1975	62	2037	57	2032	(5)
Jim Bridger-3	1976	61	2037	61	2037	—
Jim Bridger-4	1979	58	2037	58	2037	—
Naughton-1	1963	66	2029	66	2029	—
Naughton-2	1968	61	2029	61	2029	—
Naughton-3*	1971	58	2029	58	2029	—
Wyodak-1	1978	61	2039	61	2039	—
Gadsby-1 (Rankine)	1951	81	2032	81	2032	—
Gadsby-2 (Rankine)	1952	80	2032	80	2032	—
Gadsby-3 (Rankine)	1955	77	2032	77	2032	—
Blundell 1 (Geothermal)	1984	53	2037	53	2037	—
Blundell 2 (Geothermal)	2007	30	2037	30	2037	—
Gas						
Currant Creek (CCCT)	2005	40	2045	40	2045	—
Chehalis (CCCT)	2003	40	2043	40	2043	—
Hermiston 1 (CCCT)	1996	40	2036	40	2036	—
Hermiston 2 (CCCT)	1996	40	2036	40	2036	—
Lake Side 1 (CCCT)	2007	40	2047	40	2047	—
Lake Side 2 (CCCT)	2014	40	2054	40	2054	—
Gadsby-4 (CT)	2002	30	2032	30	2032	—
Gadsby-5 (CT)	2002	30	2032	30	2032	—
Gadsby-6 (CT)	2002	30	2032	30	2032	—

* To be retired in 2019

Rocky Mountain Power
Exhibit RMP___(CAT-2)
Docket No. 18-035-36
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

Estimated Decommissioning Costs

September 11, 2018

Estimated Decommissioning Costs

Values in 2017 Dollars

COAL

Generating Facility	Grand Total	$/kw
Cholla 4	$ 20,328,470	51.46
Cholla	$ 20,328,470	
Dave Johnston 1	$ 3,630,058	34.25
Dave Johnston 2	$ 3,630,058	34.25
Dave Johnston 3	$ 7,534,083	34.25
Dave Johnston 4	$ 11,301,125	34.25
Dave Johnston	$ 26,095,324	34.25
Hunter 1	$ 18,059,921	43.19
Hunter 2	$ 11,618,067	43.19
Hunter 3	$ 20,343,731	43.19
Hunter	$ 50,021,719	43.19
Huntington 1	$ 20,327,323	44.29
Huntington 2	$ 19,928,748	44.29
Huntington	$ 40,256,071	44.29
Jim Bridger 1	$ 13,171,584	37.21
Jim Bridger 2	$ 13,370,026	37.21
Jim Bridger 3	$ 12,973,142	37.21
Jim Bridger 4	$ 13,146,779	37.21
Jim Bridger	$ 52,661,531	37.21
Naughton 1	$ 15,249,202	97.75
Naughton 2	$ 19,648,011	97.75
Naughton 3	$ 27,370,363	97.75
Naughton	$ 62,267,577	97.75
Wyodak	$ 7,138,204	26.64
Wyodak	$ 7,138,204	26.64
Colstrip 3	$ 6,342,513	85.71
Colstrip 4	$ 6,342,513	85.71
Colstrip 3/4	$ 12,685,026	85.71
Craig 1	$ 1,018,471	12.37
Craig 2	$ 1,020,856	12.37
Craig	$ 2,039,327	12.37
Hayden 1	$ 203,384	4.51
Hayden 2	$ 148,938	4.51
Hayden	$ 352,322	4.51
Fleet		46.14

NATURAL GAS

Generating Facility	Grand Total	$/kw
Currant Creek	$ 6,426,778	$ 11.69
Gadsby 1, 2 and 3	$ 9,289,965	$ 39.12
Chehalis	$ 3,294,111	$ 6.36
Lake Side	$ 7,621,513	$ 6.34
Hermiston	$ 4,127,878	$ 17.42
Gadsby 4, 5, and 6	$ 1,208,209	$ 10.07

GEOTHERMAL

Generating Facility	Grand Total	$/kw
Blundell 1 (Geothermal)	$ 5,346,476	$ 232.46
Blundell 2 (Geothermal)	$ 1,392,815	$ 139.28
Blundell	$ 6,739,291	$ 204.22

Rocky Mountain Power
Docket No. 18-035-36
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Timothy J. Hemstreet

September 11, 2018

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

A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah Street, Suite 1500, Portland, Oregon 97232. My present position is Director of Renewable Energy Development. I am testifying on behalf of Rocky Mountain Power (the "Company"), a division of PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I hold a Bachelor of Science degree in Civil Engineering from the University of Notre Dame in Indiana and a Master of Science degree in Civil Engineering from the University of Texas at Austin. I am also a Registered Professional Engineer in the state of Oregon. Before joining the Company in 2004, I held positions in engineering consulting and environmental compliance. Since joining the Company, I have held positions in environmental policy, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed the role of Director of Renewable Energy Development, in which I oversee the development of renewable energy resources.

Q. Please explain your responsibilities as Director of Renewable Energy Development.

A. The renewable energy development group is responsible for identifying and developing Company-owned renewable generation resource options and efficiency improvements—including wind, solar, and hydroelectric resources—to enhance or improve the efficiency of the Company's renewable resources portfolio.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony:

- Provides an overview of the Company's recommended depreciable lives for its renewable generating resources. The Company reviewed its hydro and wind resource generating assets and performed an evaluation of depreciable lives in support of this filing. Based on this assessment, the Company proposes certain changes to the depreciable lives established in the previous depreciation study filed in Docket No. 13-035-02 ("2013 depreciation study").[1]
- Describes how the Company developed estimated plant economic lives for its wind and hydro generation resources included in the Company's new depreciation study submitted with Company witness Mr. John J. Spanos's testimony as Exhibit RMP___(JJS-2) (the "Depreciation Study") in this filing. My testimony also summarizes the proposed changes in the depreciable plant lives of the renewable resources and the basis therefore including updated information regarding new and anticipated hydroelectric operating licenses, the repowering of the Company's existing wind fleet, as well as the assumed depreciation lives for new wind resources that will be brought online in 2020.

Q. Have you provided the Company's estimated plant economic lives for its renewable generation assets?

A. Yes. Exhibit RMP___(TJH-1) attached to my testimony contains a complete list of the Company's renewable generation plants and their recommended depreciable lives.

[1] In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for Authority to Change its Depreciation Rates Effective January 1, 2014, Docket 13-035-02.

DEPRECIABLE LIVES FOR HYDROELECTRIC GENERATION RESOURCES

Q. What is the Company's general approach for developing the depreciable lives of its hydroelectric generating facilities?

A. The Company's approach as reflected in the Depreciation Study is primarily based on Federal Energy Regulatory Commission ("FERC") hydroelectric plant license expiration dates. The vast majority of the facilities (comprising 99 percent of the Company's installed hydroelectric generating capacity) require a FERC license to operate. The terms of the FERC license requirements largely determine the capital expenditures required to make necessary improvements to the hydroelectric plant during the license period to implement protection, mitigation and enhancement measures. It is therefore appropriate for the term of the FERC license to set the depreciable life of the hydroelectric generation resource.

The status of the FERC relicensing processes for the Company's licensed hydroelectric facilities was reviewed to determine any changes required by new licensing information. These changes are due to either recent license issuances or the Company's expectations of the term of new licenses based upon the scope of likely or proposed protection, mitigation and enhancement measures that will be required during a new license term, which FERC uses to assess the appropriate new license term in a licensing order.

For its unlicensed hydroelectric facilities, the Company assessed the depreciation lives based on the current operating conditions of the facilities as observed since the last depreciation study and the estimated remaining life of the physical assets as determined by the Company's hydro resources engineering staff.

Q. What major changes did the Company make regarding the depreciable lives of its hydroelectric generating resources?

A. The major changes the Company made are driven primarily by changes in expected license terms for FERC regulated projects that have either been recently issued a new license or that the Company intends to relicense in the near future. FERC issued a new 40-year license for the Wallowa Falls project in Oregon in January 2017 so the Company extended the depreciable life of that project to 2057 to match the new license term. Additionally, the Company expects FERC to issue a new 40-year license for the Prospect No. 3 project in Oregon in late 2018 so the Company proposes extending the depreciable life of the Prospect No. 3 facility to 2058. The Company also expects that FERC will issue new 40-year licenses for the Weber and Cutler facilities in Utah when their existing licenses expire in 2020 and 2024, respectively. Exhibit RMP___(TJH-1), "PacifiCorp Estimated Plant Retirement, Lives – Renewable Resources" lists the estimated retirement dates of the Company's hydro and wind generating resources and the proposed changes to the existing depreciable lives.

Q. Why does the Company assume that the facilities it intends to relicense will be issued 40-year licenses?

A. The Company's recent experience with new license terms for projects with moderate changes or for which construction is required to comply with new license requirements, like the Wallowa Falls project, is that FERC will issue a 40-year license[2] unless unique conditions are met. This is consistent with FERC's recent "Policy Statement on

[2] The new license for Prospect No. 3 is available at https://www.ferc.gov/industries/hydropower/gen-info/licensing/active-licenses/P-308.pdf.

Establishing License Terms for Hydroelectric Projects," issued in October 2017.[3] In the policy statement, FERC adopted a default 40-year license term for licensed hydropower projects at non-federal dams. FERC also articulated that projects with limited new improvements or construction that are required under a new license could justify a shorter license term of not less than 30 years. The Company estimates that moderate infrastructure improvements will be necessary during new license terms for its hydroelectric projects; thus, a 40-year depreciable life was viewed as appropriate.

Q. Did the Company extend the depreciable life of any of its other hydro facilities for reasons other than new or anticipated license terms?

A. Yes. The Company made slight adjustments to extend the depreciable lives of several small hydro facilities with less than three megawatt capacity that are not licensed by FERC. Small extensions of between four to eight years are proposed for the Paris, Gunlock, Santa Clara, Veyo, Last Chance and Granite facilities to reflect their continuing operational status and the estimated remaining life of their physical assets. The Company also extended the depreciable lives for the Bend and Eagle Point facilities of 14 and 15 years, respectively, because these facilities will not be decommissioned in the near-term and will continue to provide service to customers for the new proposed depreciable life.

Q. Did the Company reduce the depreciable life of any of its hydro facilities?

A. Yes. The depreciable life of the Viva Naughton hydroelectric facility – a small 0.74 megawatt capacity hydroelectric facility located at the cooling water storage reservoir for the Naughton steam generating facility in Wyoming – was reduced by

[3] FERC's policy statement is available at https://www.ferc.gov/whats-new/comm-meet/2017/101917/H-1.pdf.

11 years, from 2040 to 2029, to reflect the planned retirement date of the Naughton steam generating station.

Q. Has the Company proposed any changes to the estimated retirement date of its Klamath hydroelectric assets?

A. No, the Company's estimated retirement dates for the Klamath hydroelectric facilities are unchanged from the 2013 depreciation study and remain consistent with the timing of decommissioning anticipated by the Klamath Hydroelectric Settlement Agreement.

Q. Could environmental issues affect the estimated plant economic life of hydro resources in the future?

A. Yes. While no new significant environmental compliance issues have emerged since the 2013 depreciation study, the dynamic nature of evolving environmental stewardship requirements and FERC licensing requirements, coupled with asset specific attributes will continue to impact the Company's ability to economically achieve license extensions or economically operate unlicensed hydro facilities for the benefit of customers. For instance, assets that must mitigate project effects on species listed under the Endangered Species Act may be subject to unique environmental stewardship requirements, which can change based upon the status of the listed species. On the other hand, long-term investments the Company is making to comply with its current license requirements – such as the installation of fish passage measures at many of its newly relicensed hydroelectric facilities – may positively influence the ability to relicense these facilities in the future and continue economic operation. If conditions change as a result of evolving requirements or unforeseen circumstances, the depreciable lives of the Company's hydroelectric assets will be adjusted accordingly in a future depreciation.

DEPRECIABLE LIVES FOR NEW WIND GENERATING RESOURCES

Q. Please describe the process the Company used to assess the depreciable lives of its wind resources.

A. In the Company's 2013 depreciation study, the Company recommended, and the Commission adopted, extending the previously assumed 25-year depreciable life for its wind-powered generation resources to 30 years. The Company has assessed this depreciable life against current industry trends for wind generation facilities and continues to believe that a 30-year depreciable life is appropriate for such facilities whose wind turbine generators are designed to meet industry standards and that are maintained consistent with manufacturer recommendations. New wind projects require a greater investment per turbine due to the larger wind turbine size as compared to earlier turbine technologies. Thus, some new utility-owned wind assets, for which ongoing generation offtake and maintenance funding is more certain, have been considered for longer asset lives of up to 40 years.

Q. What asset life is the Company proposing for the new wind facilities that are currently being developed and expected to enter service in 2020?

A. The Company is currently developing 950 megawatts of new wind facilities in Wyoming associated with its Energy Vision 2020 project that are expected to commercially operate in 2020. The Company proposes a 30-year asset life for these new facilities, consistent with the 30-year asset life for the Company's existing wind facilities that was approved in the 2013 depreciation study.

Q. Is a 30-year asset life consistent with how the Company evaluated proposed new wind projects as part of its Energy Vision 2020 proposal?

A. Yes, in the Energy Vision 2020 cases, the Company assumed a 30-year asset life for new Company-owned wind assets as part of such new wind resources' economic evaluation.

DEPRECIABLE LIVES FOR REPOWERING WIND GENERATING RESOURCES

Q. Is the Company proposing changes to the depreciable lives of its existing wind resources?

A. Yes. The Company is currently repowering the majority of its existing wind fleet, which, for its wind facilities constructed between 2006 and 2010, will result in the replacement of the existing nacelles and rotors at the facilities with more modern equipment that includes longer blades and higher capacity generators.[4]

Repowering of the Company's wind fleet will benefit customers by requalifying the repowered facilities for the full value of available production tax credits when brought online by the end of 2020, increasing zero-fuel cost generation from the existing wind fleet by an average of approximately 26 percent, and extending the asset lives of the repowered facilities. The Company plans to repower its existing wind facilities in 2019 and 2020. The Company therefore recommends extending the depreciable lives of the repowered facilities to provide for a 30-year asset life after the repowering equipment upgrades are installed. This results in an extension of the depreciable lives of the Company's existing wind facilities by 10 to 21 years,

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[4] The Company is also evaluating repowering its Foote Creek I facility, which would involve the replacement of the existing wind turbine generators installed in 1999 with new, modern equipment. The Company anticipates that this facility will be repowered in 2020 if satisfactory arrangements are obtained and permits are received that would allow this facility to be repowered and provide benefits to customers as compared to the status quo.

depending on the facility. The Company's proposed depreciable lives for its wind facilities are shown in Exhibit RMP___(TJH-1).

Q. What are the current asset lives of the wind facilities to be repowered?

A. All of the existing wind facilities are currently being depreciated assuming a 30-year asset life. The facilities the Company plans to repower or is evaluating for repowering are currently scheduled to be retired between 2029 and 2040. The retired assets from repowering are treated as an interim retirement for accounting purposes and transfered to the wind plant depreciation reserve.

Q. Will repowering the wind facilities extend their useful operating lives beyond the currently planned retirement dates?

A. Yes, the Company believes that repowering the wind facilities will extend their operation 30 years from the repowering date, extending their useful lives by at least 10 years.

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

A. The repowering projects are being designed by the turbine equipment suppliers to meet the same design requirements that apply to complete wind turbine generators used in new wind facility construction. The wind turbine equipment suppliers will have their wind turbine designs for the repowering projects certified by an independent third party to ensure that they meet or exceed applicable International Electrotechnical Commission design standards used in the wind turbine industry. These design standards are intended to ensure that the equipment is appropriate for the site conditions and will perform satisfactorily over the standard design life.

Q. What factors are independently reviewed to assess and certify the design of the repowered wind facilities?

A. The third-party design assessment evaluates the site-specific load assumptions based upon the climactic conditions at each facility and will assess the control and protection systems for the wind turbine and their ability to meet the site design conditions. It will also assess the electric components, the rotor blades, hub, machine components (i.e., drivetrain, main bearing and gearbox), and the suitability of the existing tower upon which the new wind turbine equipment will be installed to meet the new design loads.

Q. Does the Company have land rights that allow its repowered wind facilities to operate for 30 years after repowering?

A. The Company reviewed its existing land rights for its existing wind generation facilities and determined that nearly all projects have land rights that will allow the facilities to operate for 30 years after repowering is completed. The Company will seek to prudently extend lease terms beyond the initial period, as required, to support the longer depreciable lives of its repowered wind resources.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(TJH-1)
Docket No. 18-035-36
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Existing and Proposed Depreciable Lives for Renewable Resources

September 11, 2018

Existing and Proposed Depreciable Lives for Renewable Resources

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PACIFICORP HYDRO PLANTS

Plant	Nameplate Rating (MW)	Year Installed	FERC License Number	License Expiration Date	Energy Source	State	Location	2013 Stipulated Depreciation End Year	New Proposed Plant Depreciation End Year	Asset Life Extension/ (Reduction) (years)
Ashton	6.85	1910	2381	12/31/2027	Henry's Fork Snake River	Idaho	Ashton, ID	2027	2027	—
Bend	1.11	1913		Unlicensed	Deschutes River	Oregon	Bend, OR	2016	2030	14
Big Fork	4.15	1910	2652	6/30/2053	Swan River	Montana	Big Fork, MT	2053	2053	—
Clearwater No.1	15.00	1953	1927	10/31/2038	Clearwater River	Oregon	Toketee Falls, OR	2038	2038	—
Clearwater No.2	26.00	1953	1927	10/31/2038	Clearwater River	Oregon	Toketee Falls, OR	2038	2038	—
COPCO No.1	20.00	1918	2082	2/28/2006	Klamath River	California	Hombrook, CA	2019	2019	—
COPCO No.2	27.00	1925	2082	2/28/2006	Klamath River	California	Hombrook, CA	2019	2019	—
Cutler	30.00	1927	2420	3/31/2024	Bear River	Utah	Logan, UT	2024	2064	40
Eagle Point	2.81	1957		Unlicensed	South Fork Big Butte Creek	Oregon	Shady Cove, OR	2025	2040	15
East Side	3.20	1924	2082	2/28/2006	Link River	Oregon	Klamath Falls, OR	2020	2020	—
Fall Creek	2.20	1903	2082	2/28/2006	Fall Creek	California	Hombrook, CA	2020	2020	—
Fish Creek	11.00	1952	1927	10/31/2038	Fish Creek	Oregon	Toketee Falls, OR	2038	2038	—
Grace	33.00	1908	20	11/30/2033	Bear River	Idaho	Grace, ID	2033	2033	—
Granite	2.00	1896		Unlicensed	Big Cottonwood Creek	Utah	Salt Lake City, UT	2030	2035	5
Gunlock	2.05	1917	9281	Exempt	Santa Clara River	Utah	St. George, UT	2020	2024	4
Iron Gate	18.00	1962	2082	2/28/2006	Klamath River	California	Hombrook, CA	2019	2019	—
J. C. Boyle	97.98	1958	2082	2/28/2006	Klamath River	Oregon	Keno, OR	2019	2019	—
Keno Regulating Dam	—	1967	2082	2/28/2006	Link River	Oregon	Klamath Falls, OR	2020	2020	—
Klamath Lake Reservoir	—	1919		Unlicensed	Link River	Oregon	Klamath Falls, OR	2020	2020	—
Last Chance	1.73	1984	4580	Exempt	Last Chance Canal	Idaho	Grace, ID	2025	2033	8
Lemolo No.1	31.99	1955	1927	10/31/2038	North Umpqua River	Oregon	Toketee Falls, OR	2038	2038	—
Lemolo No.2	38.50	1956	1927	10/31/2038	North Umpqua River	Oregon	Toketee Falls, OR	2038	2038	—
Lifton Pump Station	—	1918		Unlicensed	Bear River	Idaho	St. Charles, ID	2033	2033	—
Merwin	136.00	1931	935	6/1/2058	North Fork Lewis River	Washington	Areil, WA	2058	2058	—
Oneida	30.00	1915	20	11/30/2033	Bear River	Idaho	Preston, ID	2033	2033	—
Paris	0.72	1910	703	Exempt	Paris Creek	Idaho	Preston, ID	2017	2024	7
Pioneer	5.00	1897	2722	8/31/2030	Ogden River	Utah	Ogden, UT	2030	2030	—
Prospect No.1	3.76	1912	2630	4/1/2038	North Fork Rogue River	Oregon	Prospect, OR	2038	2038	—
Prospect No.2	32.00	1928	2630	4/1/2038	North Fork Rogue River	Oregon	Prospect, OR	2038	2038	—
Prospect No.3	7.20	1932	2337	12/31/2018	North Fork Rogue River	Oregon	Prospect, OR	2018	2058	40
Prospect No.4	1.00	1944	2630	4/1/2038	South Fork Rogue River	Oregon	Prospect, OR	2038	2038	—
Santa Clara		1920	9281	Exempt	Santa Clara River	Utah	St. George, UT	2020	2024	4
Slide Creek	18.00	1951	1927	10/31/2038	North Umpqua River	Oregon	Toketee Falls, OR	2038	2038	—
Soda	14.00	1924	20	11/30/2033	Bear River	Idaho	Soda, ID	2033	2033	—
Soda Springs	11.00	1952	1927	10/31/2038	North Umpqua River	Oregon	Toketee Falls, OR	2038	2038	—
Stairs	1.00	1895	597	6/30/2030	Big Cottonwood Creek	Utah	Salt Lake City, UT	2030	2030	—
Swift	240.00	1958	2111	6/1/2058	North Fork Lewis River	Washington	Cougar, WA	2058	2058	—
Toketee	42.50	1949	1927	10/31/2038	North Umpqua River	Oregon	Toketee Falls, OR	2038	2038	—
Veyo		1920	9281	Exempt	Santa Clara River	Utah	St. George, UT	2020	2024	4
Viva Naughton	0.74	1986		Exempt	Ham's Fork River	Wyoming	Kemmerer, WY	2040	2029	(11)
Wallowa Falls	1.10	1921	308	2/28/2016	East Fork Wallowa River	Oregon	Joseph, OR	2016	2057	41
Weber	3.85	1911	1744	5/31/2020	Weber River	Utah	Ogden, UT	2020	2060	40
West Side	0.60	1908	2082	2/28/2006	Link River	Oregon	Klamath Falls, OR	2020	2020	—
Yale	134.00	1953	2071	6/1/2058	North Fork Lewis River	Washington	Cougar, WA	2058	2058	—
Total Capacity	**1,057.04**									

Existing and Proposed Depreciable Lives for Renewable Resources

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PACIFICORP WIND PLANTS

Existing Wind Resources

Wind Project	Nameplate Rating (MW)	Commercial Start Date	Years in Operation	State	Location	Planned Repowering Year	2013 Stipulated Depreciation End Year	Proposed Retirement Year	Asset Life Extension (years)
Dunlap I	111.0	10/1/2010	7.9	Wyoming	Medicine Bow, WY	2020	2040	2050	10
Foote Creek	32.1	4/22/1999	19.3	Wyoming	Arlington, WY	2020	2029	2050	21
Glenrock I	99.0	12/31/2008	9.6	Wyoming	Glenrock, WY	2019	2038	2049	11
Glenrock III	39.0	1/17/2009	9.6	Wyoming	Glenrock, WY	2019	2038	2049	11
Goodnoe Hills	94.0	5/31/2008	10.2	Washington	Goldendale, WA	2019	2038	2049	11
High Plains	99.0	9/13/2009	8.9	Wyoming	McFadden, WY	2019	2039	2049	10
Leaning Juniper	100.5	9/14/2006	11.9	Oregon	Arlington, OR	2019	2036	2049	13
Marengo I	140.4	8/3/2007	11.0	Washington	Dayton, WA	2019	2037	2049	12
Marengo II	70.2	6/26/2008	10.1	Washington	Dayton, WA	2019	2038	2049	11
McFadden Ridge	28.5	9/29/2009	8.9	Wyoming	McFadden, WY	2019	2039	2049	10
Rolling Hills	99.0	1/17/2009	9.6	Wyoming	Glenrock, WY	2019	2039	2049	10
Seven Mile Hill I	99.0	12/31/2008	9.6	Wyoming	Medicine Bow, WY	2019	2038	2049	11
Seven Mile Hill II	19.5	12/31/2008	9.6	Wyoming	Medicine Bow, WY	2019	2038	2049	11
Total Capacity	**1,031.2**		**Total Capacity**						

New Wind Resources

Wind Project	Nameplate Rating (MW)	Commercial Start Date	Years in Operation	State	Location	Planned Repowering Year	2013 Stipulated Depreciation End Year	Proposed Retirement Year	Asset Life Extension (years)
TB Flats I&II	500.0	2020	—	Wyoming	Medicine Bow, WY	—	—	2050	—
Cedar Springs	200.0	2020	—	Wyoming	Medicine Bow, WY	—	—	2050	—
Ekola Flats	250.0	2020	—	Wyoming	Medicine Bow, WY	—	—	2050	—
Total Capacity	950.0								