BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Michael G. Wilding and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Vice President, Energy Supply Management ("ESM").

Q. Please describe your education and professional experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University and am a Certified Public Accountant licensed in the state of Utah. During my tenure at the Company, I have worked on various regulatory projects including general rate cases, the multi-state protocol, and net power cost filings. I have been employed by PacifiCorp since 2014.

Q. Please explain your responsibilities as PacifiCorp's Vice President of ESM.

A. My current responsibilities include directing PacifiCorp's front office organization or ESM in commercial and trading activities. ESM is responsible for commercially managing PacifiCorp's diverse generation portfolio. This includes the electric and natural gas hedging, term and day-ahead trading, real-time trading, and system balancing. I also manage PacifiCorp's renewable energy credit ("REC") portfolio including the sale of RECs in excess of compliance requirements.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Idaho Public Utilities Commission ("Commission"), and the public utility commissions in California, Oregon, Utah, Washington, and Wyoming.

II. SUMMARY AND PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to present the Company's proposed net power costs ("NPC") for the 12-month period ending December 31, 2021 ("test period"). The proposed NPC will become the new base NPC for the Energy Cost Adjustment Mechanism ("ECAM"), beginning January 1, 2022. Specifically, my testimony:

- Summarizes forecasted NPC for the 2021 test period in this general rate case ("GRC") and explains the calculation of NPC using the Company's Generation and Regulation Initiative Decision Tools ("GRID") model;
- Describes several modeling changes the Company has made in order to improve the NPC forecast accuracy since the base NPC rates were reset in Case No. PAC-E-16-12, based on the 2015 Annual Results of Operations Report ("2015 Update");
- Explains the primary drivers behind the decrease in NPC compared to the current base NPC approved by the Commission and incorporated into customer rates in the 2015 Update, that includes a discussion of the changes to the Company's resource portfolio since that time; and,

- Discusses the Company's treatment of its participation in the Western Energy Imbalance Market ("EIM") and the expected incremental benefits relative to the NPC forecast produced by the GRID model.

Q. Is there a summary of the proposed ECAM Base amounts to be set in this filing for future ECAM filings?

A. Yes. Exhibit No. 44 attached to the testimony of Mr. Steven R. McDougal, summarizes the proposed base amounts for all elements for ECAM deferrals beginning January 1, 2022. In addition to NPC discussed in my testimony, the ECAM deferral includes the difference between actual and base amounts for production tax credits, renewable energy certificate sales, and load change adjustment revenues.

III. SUMMARY OF COMPANY NET POWER COSTS

Q. Please explain the components of the Company's NPC.

A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. The NPC forecast approved in this case becomes the base NPC used for comparison to actual NPC in subsequent ECAM filings.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for the test period based on projected data using GRID, a production cost model that simulates the operation of the Company's power system on an hourly basis. GRID respects all system requirements and constraints and uses incremental pricing to dispatch the Company's generation units for a cost minimizing output where demand and supply are balanced.

Q. Is the Company's general approach to the calculation of NPC using the GRID model the same in this case as in previous cases?

A. Yes. The Company has used the GRID model to determine NPC in its Idaho filings for many years. However, to improve the accuracy of the NPC forecast, the Company has implemented certain modeling changes in this case.

Q. What GRID inputs were updated for this filing?

A. All inputs have been updated since the 2015 Update, including system load, wholesale sales and purchase contracts for electricity, wheeling expense, market prices for electricity and natural gas also known as the Official Forward Price Curve ("OFPC"), transmission topology, and the characteristics and availability of the Company's generation facilities.

Q. What is the date of the OFPC the Company used for its NPC?

A. The NPC used the OFPC dated March 31, 2021.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is attached to my testimony as Exhibit No. 37. The GRID model also produces more detailed reports in hourly, daily, monthly, and annual formats by heavy-load hours ("HLH") and light-load hours ("LLH").

Q. What are the proposed system-wide NPC for the test period?

A. The proposed NPC for the test period are $1,365 million on a total-Company basis and $86.5 million on an Idaho-allocated basis.

Q. Please generally describe the changes in NPC compared to the 2015 Update.

A. The decrease in NPC is driven by lower coal fuel expense, lower natural gas expense, increased zero-fuel cost renewable generation, and increased wholesale sales revenue. The decrease is partially offset by an increase in wheeling and purchased power expense. Figure 1 below illustrates the total-Company change in NPC by category compared to the NPC approved in the 2015 Update.

Figure 1

Net Power Cost Reconciliation

	($ millions)	**$/MWh**
ID Base NPC PAC-E-16-12	**$1,485**	**$25.05**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(129)	
Purchased Power Expense	237	
Coal Fuel Expense	(181)	
Natural Gas Fuel Expense	(56)	
Wheeling and Other Expense	9	
Total Increase/(Decrease) to NPC	**(120)**	
ID GRC 2021	**$1,365**	**$23.36**

As shown in Figure 1, total-Company NPC has decreased from $1,485 million to $1,365 million, which is $120 million (8.1 percent) lower than in the 2015 Update. The total-Company price per megawatt-hour ("MWh") has decreased from $25.05 per MWh to $23.36 per MWh. Unless otherwise noted, references to NPC or various individual cost items throughout my testimony are stated in total-Company system amounts.

Q. Please explain the increase in wholesale sales revenue.

A. The increase in wholesale sales revenue (which decreases NPC) is driven by higher wholesale sales volumes, which are 2,960 gigawatt-hours ("GWh") higher than in the 2015 Update. Wholesale sales revenue is $129 million higher than the 2015 Update with the increase coming from market transactions (represented in GRID as short-term firm, and system balancing sales). The increase in volume is driven by higher average market prices forecast in the test period. The average market price of wholesale sales is $43.62 per MWh, an 86 percent increase over the average market sale price in the 2015 Update, which was $23.46 per MWh.

Q. Why did purchased power expense increase?

A. The increase in purchased power expense is driven by an increase in the volume of system balancing purchases as well as higher system balancing prices. Additionally, the volume of long-term purchases has increased, primarily in the form of purchases from qualified facilities ("QFs"). Market purchases (represented in GRID as short-term firm and system balancing purchases) in the current case have an average price of $35.41 per MWh, while the 2015 Update had an average price of $25.06 per MWh, a rise of approximately 41 percent. The market purchase volume is 767 GWh higher than in the 2015 Update on a total-Company basis.

This case also includes nine new long-term contracts with an average price of $19.08 per MWh, with the expiration of four long-term contacts with an average price of $65.68 per MWh.

Several new QFs have come online since the 2015 Update. The total expense for power purchased from QFs increased by $122 million which is driven by an anticipated generation volume increase of 2,068 GWh compared to the 2015 Update. The average price for QFs included in this case is $59.39 per MWh, compared to the average price of QFs in the 2015 Update of $59.55 per MWh.

Q. Please explain the decrease in coal expense in the current proceeding.

A. Total-Company coal fuel expense is $180.5 million lower than the 2015 Update due to lower coal generation volume, partially offset by higher coal prices, and increased generation from zero fuel cost renewable resources. The lower coal fuel expense is driven in part by the closure of the Cholla Unit 4 power plant, which the Company removed from service in December 2020. Excluding the impacts of the closure of Cholla Unit 4, coal generation is approximately 6,835 GWh or 19 percent, lower than the 2015 Update. The average coal generation price across PacifiCorp's generation fleet is $0.12 per MWh higher than the average coal generation price from the 2015 Update. The increase is driven by changes in third-party coal supply and rail contracts. I provide additional detail regarding the coal fuel expense later in my testimony.

Q. Please discuss the change in natural gas fuel expense compared to the 2015 Update.

A. Total-Company natural gas fuel expense is $56 million lower than the natural gas fuel expense in the 2015 Update. The decreased natural gas fuel expense is primarily due to lower forecasted generation volume, partially offset by higher natural gas market prices. The average cost of natural gas generation increased 17 percent from $23.06 per MWh to $26.95 per MWh in the current proceeding. Generation from natural gas power plants is 3,862 GWh less than the 2015 Update, a decrease of 31 percent.

Q. Please describe the increase in the wheeling and other expense category.

A. Expenses in this category are higher due to an $8 million service fee charged by the California Independent System Operator ("CAISO") for grid management related to the new nodal pricing model developed as a requirement of the 2020 inter-jurisdictional cost allocation agreement, and expedited payment schedule for the Mead-Phoenix Transmission line amortization due to the Cholla 4 retirement in December 2020. This increase is partially offset by the expiration of some legacy wheeling contracts.

Q. Please explain the changes to the Company's generation resources since the 2015 Update.

A. There have been multiple changes to the Company's generation resources since the 2015 Update. The following is a list of some of the major changes affecting NPC:

- *Cholla Unit 4 Termination* – Cholla Unit 4 was removed from service in December 2020, and will not operate during the test period;
- *Naughton Unit 3 Gas Conversion* – Naughton Unit 3 was converted from a coal-fired resource to a natural gas resource in 2020;
- *New Renewable Resources* – Approximately 1,500 MW of new owned wind and transmission, along with other power purchase agreements are included in the test period.

IV. MODELING CHANGES TO GRID

Q. Has the Company made any changes to improve the accuracy of its NPC modeling?

A. Yes. The Company has made various modifications to the GRID inputs in order to increase the accuracy of forecast NPC, including changes to the following items:

- Updated the scalar method for the OFPC;
- Updated the regulating reserve requirement based on the Flexible Reserve Study in the 2019 Integrated Resource Plan ("IRP");

- Included actual capacity factors for owned wind power plants and purchased wind power plants; and
- Developed a solar hourly profile consistent with the method used for the wind hourly profile.

Details supporting each modeling change are provided below.

Q. Why is the Company proposing changes to NPC modeling in this case?

A. Base NPC have not been updated since 2015. The modeling changes proposed in this case are necessary to improve the accuracy of the forecast.

A. Updated Scalars to the Official Forward Price Curve

Q. Please briefly describe the hourly scalars and how they are applied to the OFPC the Company used in GRID.

A. Scalars are multipliers that are applied to the monthly prices from the OFPC to derive an hourly price profile. In other words, scalars give the monthly prices an hourly shape. These multipliers are unique for every hour in a month for a given day type (i.e., weekdays excluding holidays, Saturdays excluding holidays, and Sundays/holidays), and therefore yield hour-to-hour price variability that is consistent with historical price data. Scalars greater than one would result in an hourly price for a given day type that is higher than the monthly forward price, and scalars that are less than one would result in an hourly price for a given day type that is lower than the monthly forward price. For example, if the average market price during hour-ending at 10 am in May is $18 per MWh, and the average market price during all hours in May is $20 per MWh, then the scalar for hour-ending at 10 am in May would be 0.9 or 90 percent.[1] The hourly

[1] $18 per MWh divided by $20 per MWh equals 0.9 or 90 percent.

price profile that is a result of applying scalars to forward monthly prices yields hourly prices that, when averaged across a given month, precisely equal the forward monthly prices in the OFPC.

Q. Please explain the change to the hourly scalars used in this case.

A. To better reflect ongoing changes in power markets and to increase transparency, PacifiCorp is no longer using five years of historical hourly prices from PowerDex. Instead, PacifiCorp is using the CAISO day-ahead hourly market prices at California-Oregon Border ("COB") and Palo Verde ("PV") for the most recent 24-month period. The change in data inputs that determine the scalars does not, however, alter the application of the scalars as described above.

Q. Why is PacifiCorp making this change to its scalars?

A. The use of the CAISO day-ahead hourly market prices as a basis for the updated forecast scalars follows the actual hourly shape by producing a peak in the morning hours, depressed prices during mid-day, and larger peak in the evening hours. This type of shape is expected given the solar penetration in the West and is the result of higher quality CAISO trade data that better reflects actual and ongoing conditions in the power markets. The volume of actual trade data reported from CAISO is substantially higher than the volume of actual trade data that is reported in PowerDex. The use of the CAISO trade data results in scalars that better represent the increasing solar capacity in California and price volatility on a day-ahead basis. Finally, the historical CAISO day-ahead hourly prices are publicly available resulting in greater transparency compared to the proprietary PowerDex prices.

Q. Why is the use of data from the most recent 24 months reasonable?

A. The scalars give the monthly prices an hourly shape and the most recent 24 months is indicative of the hourly shapes the Company expects to see in the markets in the future. Both PacifiCorp and the western interconnect have experienced a significant increase in the number of renewable resources, including additional solar resources in the last 24 months, and this trend is expected to continue over the next several years.[2] This trend of increased solar resources has a meaningful impact on market price shape and because the industry is constantly evolving, the use of two-year data versus five years allows the Company to implement the most current market trends available.

Q. Are there considerations in the calculations of hourly scalars for very high or very low price variations?

A. Yes. CAISO prices can vary widely, and the price shape for an hour and month can be skewed by the presence of a few very high or very low prices. Therefore, the CAISO prices used to calculate the hourly scalars are capped to limit the impact of potentially more extreme results. Large price variations are generally a result of unexpected conditions, which can include significant deviations from forecasted load, wind, or solar. Such deviations are largely random, so the presence of extreme values is generally a chance occurrence, rather than a characteristic of a given hour. Therefore, the CAISO prices used to calculate the scalars are capped at +$250 per MWh and $50 per MWh.

Additionally, as the historical monthly prices approach zero, the magnitude of the shaping becomes unrealistically large. When this happens, the historical prices are

[2] U.S. Energy Information Administration. Annual Energy Outlook 2021, available at https://www.eia.gov/outlooks/aeo/pdf/04%20AEO2021%20Electricity.pdf.

uniformly shifted until the average monthly price over the calculation period is $25 per MWh, at which point, the scalars are calculated based on the adjusted historical prices resulting in a more reasonable shape.

B. Regulating Reserve Requirement

Q. How did PacifiCorp update its regulating reserve requirement modeling?

A. The Company's regulating reserve requirements are now based on the 2019 Flexible Reserve Study ("2019 FRS") that was submitted as part of the development of the 2019 IRP.[3]

Q. How has the modeling of regulating reserve requirement changed as a result of the 2019 FRS?

A. The Company included several modeling changes compared to the 2014 Wind Integration Study ("WIS") that was used in the 2015 Update:[4]

- The regulating reserve requirement is a function of a specific value that is fixed in all hours and a variable regulation reserve requirement that is based on the change in the resource balance from hour to hour.
- The regulating reserve requirement varies when wind and solar generation changes. The load and variable energy resource ("VER") have fixed amount of regulation reserve requirements. VERs refer to variable energy resources, which: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.

[3] *PacifiCorp's 2019 Integrated Resource Plan*, Case No. PAC-E-19-16.

[4] The system impact to NPC from the change of using the 2014 WIS to the 2019 FRS is difficult to quantify due to the many changes to the Company's system since the 2015 Update. Various generation resources have been added and removed from the system which affects how the regulating reserves studies are prepared and applied to NPC.

- A unit can be allocated reserves up to the lesser of its 30-minute ramp rate and the difference between its minimum and maximum operating levels. If a unit is allocated reserves, the allocated capacity is subtracted from the unit's maximum operating level, resulting in a reduced maximum dispatch level.
- The 2014 WIS included EIM diversity benefits associated with transfers between PacifiCorp's west balancing authority area and CAISO. Since then, several additional utilities have joined EIM, and diversity benefits have increased. After accounting for EIM diversity benefits, the 2014 WIS identified a total regulation requirement of approximately 561 megawatts ("MW") to integrate load and wind. The 2019 FRS identified a total regulation requirement of 531 MW to integrate load, wind and solar.

  For additional details, please refer to the Company's regulating reserve requirements based on the 2019 Flexible Reserve Study that was included in the 2019 IRP.

C. Actual Capacity Factor for Owned Wind Generation and Purchased Wind Generation

Q. Please describe the adjustment made to the forecast capacity factor for Company-owned wind generation and purchased wind generation.

A. Previously, the generation from PacifiCorp's owned wind power plants and purchased wind was based on long-range forecasts provided to the Company by the project developers. In this case, PacifiCorp proposes to calculate the annual capacity factor using a cumulative average methodology for any wind power plants with a history longer than four years. For those projects with less than four years of history, the project developer's forecast is used until four years of actual results become available at which point, actual historical data is then used.

Actual wind generation at these facilities has varied somewhat from developer forecasts, so this change brings the modeling of wind plants in line with the historical actuals, which will better reflect a reasonable level of generation for the future period.

Q. With the increase in solar generation on the Company's system, does the Company plan to use the historical average method for the forecasted capacity factor for its owned and purchased solar resources?

A. Yes. Currently, the Company uses the long-range forecasts provided by the project developers for all owned and purchased solar resources since they have been on the Company's system for less than a four-year period. The Company proposes to switch to the annual capacity factor using a cumulative average methodology for any solar power plants with a history of longer than four years.

D. Solar Hourly Shape

Q. Please explain how the Company used historical solar output to calculate the solar generation shape in this case.

A. In this case, the Company continues to use the P50[5] forecast approach for determining total solar generation and used the Company's actual 2019 energy output data from its purchased solar facilities to shape hourly solar generation profiles. The Company scaled actual generation levels up or down so that, when the output is averaged over

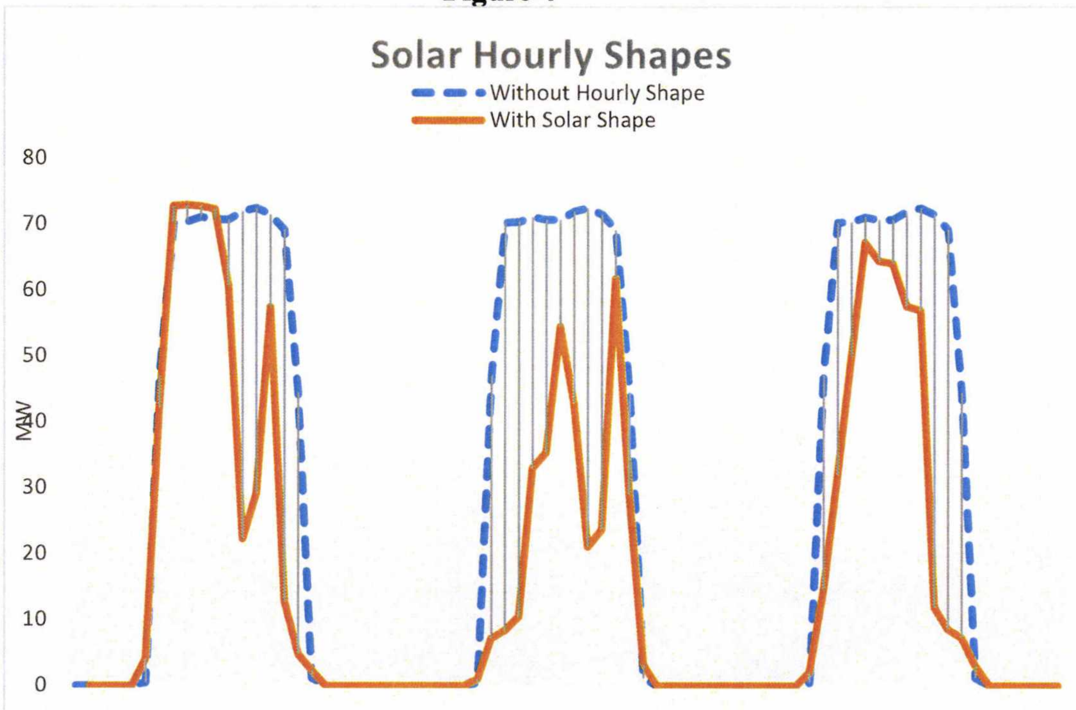
[5] A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast. Typically, such a forecast is developed for an individual project by combining solar exposure taken before the project is constructed with a detailed plant location and performance characteristics. The projected output in a given month is then averaged across a given month to produce a 12 x 24 matrix of average hourly output.

the course of a month, it is the same as in the P50 forecast. In other words, the total energy output of the solar facilities is the same as the P50 forecast used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2019. This method is consistent with the wind hourly shape method used by the Company in the 2015 Update.

Q. Why did the Company choose to use the hourly solar profile to reflect historical performance?

A. Figure 4 illustrates the difference in solar generation profiles. The solid line shows one solar plant's hourly energy, and the dashed line shows the solar hourly shape for the same dates without hourly shaping. The shaded area shows the difference between the two hourly shapes and represents the difference in solar generation for that day. The dashed line does not have any day-to-day variation in each month. The solid line better represents the solar inputs that vary hourly based on historical volatility, with the same total monthly solar generation volume as the P50 forecast.

Figure 4



V. SUMMARY OF COMPANY COAL COSTS

Q. How does PacifiCorp plan to meet fuel supplies for its coal power plants in 2021?

A. PacifiCorp employs a diversified coal supply strategy, with 81 percent of its 2021 coal requirements supplied by third-party coal supplies and 19 percent with coal from its captive affiliate mines. The third-party contracts consist of fixed-price and variable-priced contracts. Coal amounts in my testimony are shown on a total-Company basis.

A. Jim Bridger

Q. Please describe the coal supply arrangement for the Jim Bridger power plant for 2021.

A. The Jim Bridger power plant is supplied by the Company-owned Bridger Coal Company ("BCC") mine and the Black Butte mine in the test period.

Q. Please describe the change in Bridger Coal Company costs in this case.

A. BCC costs in this case are forecast to be [redacted] million lower than the 2015 Update. The cost for the BCC deliveries decreased by [redacted] per ton, from [redacted] per ton in the 2015 Update to [redacted] per ton in this case. The reduction is primarily due to the reduction of materials and supplies of [redacted] million, [redacted] million labor and benefits, [redacted] million for improved heat content, [redacted] million for an increase to the final reclamation credit, [redacted] million for coal inventory, and [redacted] million for other miscellaneous costs, partially offset by an increase of [redacted] million for final reclamation contributions. In the 2015 Update, the BCC mine plan assumed underground coal production would cease in 2023 and surface mine production would end in 2037. In this case, the BCC mine plan assumes that underground coal production will end in 2021 and surface mine production will end in 2028.

Q. What is the expected change in third-party coal prices for the Jim Bridger power plant in this case?

A. Delivered costs for the [redacted] million tons of Black Butte coal increased from [redacted] per ton in the 2015 Update to $[redacted] per ton in this case, or [redacted] million overall. The price of Black Butte coal increased [redacted] per ton, from a cost of [redacted] per ton in the 2015 Update to [redacted] per ton in this case. The coal price increase is approximately [redacted] million, or [redacted] percent. The Union Pacific Railroad agreement is forecast to increase by [redacted] million in delivered costs. These increases are primarily due to inflation.

B. Naughton

Q. Please describe the coal supply arrangement for the Naughton power plant in 2021.

A. The Naughton power plant is supplied by the adjacent Kemmerer mine under a long-term coal supply agreement ("CSA") through 2021. The CSA contains an environmental response provision to reduce the minimum annual tonnage volume quantity in the event of a reduction in coal-fired generation at the plant due to changes in environmental laws or rules.

As a result of Naughton Unit 3 converting from a coal-fired to a natural gas-fired resource,[6] PacifiCorp exercised this provision and the annual minimum take-or-pay quantity was reduced from [redacted] million tons to [redacted] million tons. In lieu of a full take-or-pay payment of approximately $[redacted] per ton or $[redacted] million for the [redacted] million tons below [redacted] million, an environmental shortfall payment of only [redacted] per ton or [redacted] million, will be owed in 2021 related to [redacted] million shortfall tons on deliveries of [redacted] million tons in the 2020-2021 contract year. For the six-month stub period from July 2021 through December 2021, an environmental shortfall payment of only [redacted] per ton or [redacted] million will be owed related to [redacted] million shortfall tons on deliveries of [redacted] million tons. The environmental shortfall payment is a direct result of the reduction in the coal purchases due to Naughton Unit 3 discontinuing as a coal-fired unit.

[6] As discussed in the direct testimony of Mr. Robert Van Engelenhoven in this case.

Q. Please describe the changes to Naughton power plant's coal cost from the 2015 Update.

A. Total delivered coal cost at Naughton increased [redacted] per ton, from [redacted] per ton in the 2015 Update to [redacted] per ton in this case resulting in an overall increase of [redacted] million. The 2021 price forecast is based upon the 2019 price reopener with escalations based upon projected diesel fuel prices and other price indices. The contract escalation results in a price increase of [redacted] million after royalties and taxes. Another driver of the price increase is the [redacted] million environmental shortfall payment in 2021. The change in the amount of coal purchased under each price tier—namely less lower-priced tier-2 coal—increases costs by [redacted] million. The forecasted tier-2 coal delivered in calendar year 2021 is [redacted] tons less than the 2015 Update. The increase in coal costs is partially offset by a decrease to the diesel fuel hedge loss of [redacted] million and a reduction of [redacted] million for contract amortization costs. The amortization of these costs was completed at the end of 2016.

C. Wyodak

Q. Please describe the price increase related to the Wyodak power plant contract.

A. Delivered coal cost increased from [redacted] per ton in the 2015 Update to [redacted] per ton in this case, or [redacted] million overall. The cost increase is primarily the result of escalation in diesel fuel and other contract indices, partially offset by the results of the 2019 price reopener.

D. Dave Johnston

Q. Please describe the Dave Johnston power plant coal supply cost increase.

A. Dave Johnston power plant delivered coal cost decreased by [redacted] million compared to the 2015 Update, or [redacted] percent. The reduction is due to a decrease in coal costs of [redacted] million, as described in further detail below partially offset by an increase in rail costs of approximately [redacted] million.

Q. Please describe the open coal position for the Dave Johnston power plant in 2021.

A. The Dave Johnston power plant is projected to consume approximately [redacted] million tons in 2021; the Company currently has [redacted] million tons of coal under contract for the plant resulting in an unidentified or open position of [redacted] million tons. The Company will solicit coal supplies from Powder River Basin ("PRB") mines through a request for proposals during 2021 to fill a reasonable portion of the open position, which may be adjusted according to market conditions. The Company has used this fueling strategy for the Dave Johnston power plant for several years.

Q. What are the coal supply arrangements for the Dave Johnston power plant in this case?

A. Arch Coal's Coal Creek mine will supply [redacted] million tons, Peabody Energy's North Antelope Rochelle mine will supply [redacted] million tons and Peabody Energy's Caballo mine will supply [redacted] million tons in 2021 ([redacted] percent of the plant's requirements). The coal cost decrease of [redacted] million is the aggregate of a decrease of [redacted] million for refined coal and a decrease to the cost of coal of [redacted] million, partially offset by an increase to the rail costs of [redacted] million.

E. Hunter

Q. Please explain how the Company's Hunter power plant is supplied with coal in this case.

A. The Hunter plant has two coal supply agreements to fuel the plant. One is with Wolverine Fuels, LLC (Wolverine) and the other is with Bronco Utah Operations, LLC (Bronco). Both agreements are "delivered to plant" agreements.

Q. Please describe the change in coal costs at the Hunter power plant in this case.

A. Coal prices have decreased [redacted] per ton, from [redacted] per ton in the 2015 Update to [redacted] per ton in this case ([redacted] million overall). The [redacted] million decrease is primarily due to the price decreases for the new CSA(s) beginning in 2021 for a decrease of [redacted] million, [redacted] million for refined coal and [redacted] million for the expiring Westridge agreement, partially offset by a [redacted] million for the Energy West pension costs.

F. Huntington

Q. Please describe the coal supply arrangement for the Huntington power plant in 2021.

A. The primary coal supply to the Huntington power plant is provided through a requirements CSA with Wolverine. This is a "delivered to the plant" agreement with Wolverine responsible for transportation of the coal from the sourced mines to the plant, although PacifiCorp is responsible for limited trucking cost escalation. In the 2015 Update, the Huntington power plant also received coal under a CSA with Rhino Energy, LLC's Castle Valley mine. That CSA ended December 31, 2020.

Q. What coal supply costs for the Huntington power plant are included in this case?

A. For the Huntington power plant, delivered coal prices increased from [redacted] per ton in the 2015 Update to [redacted] per ton in this case, an overall increase of [redacted] per ton or [redacted] million. The overall price per ton for the Wolverine contract increased [redacted] per ton, from [redacted] per ton in the 2015 Update to [redacted] per ton in this case, [redacted] million overall on [redacted] million tons. The increase is due to contractual price changes and escalation associated with transportation costs.

Q. Does the current proceeding reflect Energy West pension costs?

A. Yes. This proceeding includes [redacted] million, PacifiCorp's share, for contributions to the 1974 United Mine Workers Association pension plan.[7] [redacted] million of the pension cost is included in the Huntington plant fuel costs and [redacted] million, is included in the Hunter plant fuel costs in this case.

G. Craig

Q. Please describe the coal supply arrangements for the Craig power plant.

A. In 2021, the Craig power plant will be supplied by the Trapper mine, which is an affiliate captive mine owned by three of the five Craig power plant owners. PacifiCorp's share of the mine is 29.14 percent. The pricing under the CSA is based upon the annual mine cost associated with the Trapper mine.

Q. Have coal costs changed from the 2015 Update?

A. Yes. For the Craig power plant, delivered coal prices decreased from [redacted] per ton in the 2015 Update to [redacted] per ton in this case, for a decrease of [redacted] million. Trapper mine costs have decreased [redacted] per ton, from [redacted] per ton in the 2015 Update to

[7] *In the Matter of the Application of Rocky Mountain Power for Approval of a Transaction to Close Deer Creek Mine and for a Deferred Accounting Order*, 2015 WL 3440548, PAC-E-14-10 (Order 33304) (May 27, 2015).

[redacted] per ton in this case, a [redacted] million overall price decrease. The price decrease is due to increased volume from the Trapper mine and decreases to overall mining costs at the Trapper mine. There is also a decrease due to the reduction of diesel fuel hedge losses of [redacted] million.

H. Hayden

Q. Please describe the change in Hayden power plant's coal cost from the 2015 Update.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2015 Update to [redacted] per ton in this case. The increase is primarily due to inflation, partially offset by the 2018 price reopener. Under the terms of the January 1, 2018 reopener provision, the coal price was lowered and adjusts on a fixed annual schedule from 2018 to 2022.

I. Colstrip

Q. Please describe the change in coal cost at the Colstrip power plant in this case.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2015 Update to [redacted] per ton in this case, an increase of [redacted] million. PacifiCorp based the costs for the Colstrip power plant on the new CSA that was signed December 5, 2019. The CSA has changed from a [redacted].

Q. Please summarize how the changes to the coal fuel expenses described in this section affect NPC in this case.

A. Customers have benefited from the Company's diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fired power plants. Several factors have contributed to the $181 million decrease in coal-fuel expense in this filing, primarily reduced coal volumes. PacifiCorp's fueling strategy has resulted in long-term, stable coal supplies for its customers.

VI. CUSTOMER BENEFITS OF THE ENERGY IMBALANCE MARKET

Q. Please describe the EIM and the Company's participation in the EIM.

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and among PacifiCorp, the CAISO and other EIM participants. Through the EIM, the Company's participating generation units are optimally scheduled and dispatched using the CAISO's security constrained unit optimization and economic dispatch models. The EIM's automated, expanded footprint and co-optimized dispatch replaced the Company's isolated and manual dispatch within its two balancing authority areas ("BAAs"). Participation in the EIM benefits customers by reducing NPC, with relatively low ongoing operation costs.

Q. Has the EIM continued to provide customer benefits since the 2015 Update?

A. Yes. The Company has participated in the EIM since 2014. The EIM has continued to provide benefits to customers through more efficient and economical dispatch, inter-regional transfers (i.e., exports and imports between EIM participants), reduced reserve requirements, and greenhouse gas ("GHG") revenue. Each year the benefits have increased as regional participation in the inter-regional markets has increased.

Q. Please summarize the EIM benefits included in this case.

A. The NPC forecast from GRID includes an adjustment to reflect incremental EIM benefits from inter-regional dispatch reduced flexibility reserves, and GHG revenue. Specifically, the NPC forecast includes approximately [redacted] million in EIM benefits and [redacted] million in GHG revenue. In this case, the Company's share of the reserve benefit based on the diversified footprint of the EIM is explicitly accounted for and the regulating reserve requirement is reduced by approximately 104 MW.[8]

Q. What are the EIM inter-regional transfer benefits?

A. The inter-regional transfer benefits reflect the benefits received by PacifiCorp when it economically exports energy to the EIM and when it economically imports energy from the EIM which allows displacement of a more expensive resource on the Company system. Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the Company's calculation of EIM benefits is the marginal cost to produce an additional MWh at a given resource. The Company's production costs used to calculate EIM benefits are equal to the resource bids submitted to the EIM. The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.

Q. How does the Company calculate the inter-regional dispatch EIM benefits forecast?

A. The Company uses historical actual EIM inter-regional transfer benefits in statistical models to forecast EIM transfer benefits as a function of market prices and transfer volume inputs, which are the underlying drivers of actual EIM transfer benefits. The price inputs are the energy and natural gas market prices from the OFPC. The transfer volume inputs are the total transfer capacity of transmission along with spring oversupply conditions, based on the current and expected solar capacity in California. This market fundamentals approach to forecasting EIM transfer benefits mimics the

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[8] *See* 2019_Integrated Resource Plan,_Volume_II,_Appendices_A-L, Appendix F, pp. 101-102 , Case No. PAC-E-19-16 (October 18, 2019).

method which the Company uses to calculate actual EIM transfer benefits and maintains consistency with the bilateral market price inputs that drive the Company's GRID forecasted NPC. By utilizing the same inputs for the forecast of EIM inter-regional transfer benefits and the calculation of actual EIM inter-regional transfer benefits the GRID forecasted NPC are aligned and produce a reasonable forecast of EIM inter-regional transfer benefits. The regression modeling for this rate case is a method which provides the comprehensive view from all the variables actually impacting inter-regional EIM benefits in the future.

Q. How does the Company calculate the EIM GHG benefits?

A. GHG benefits are realized when the GHG revenue is higher than the Company's resulting compliance cost. GHG revenues are received from the energy dispatched to serve the CAISO's GHG obligations and the associated payment for GHG compliance costs, which is embedded within the EIM price as the marginal cost of GHG. The Company's compliance cost is the expenditure to procure the necessary California Carbon Allowances for the portion of the energy dispatched to serve the CAISO's GHG obligations.

VII. CONCLUSION

Q. Please summarize your direct testimony.

A. The Company's NPC for the 2021 test period in this case have decreased by \$120 million on a total-Company basis, 8.1 percent, since the 2015 Update. This reduction is largely driven by reductions in coal fuel expense, increased sales revenue, lower natural gas fuel expense, and increased zero-fuel cost renewable generation, partially offset by increased purchased power expense, and a small increase in wheeling expense. The Company has updated its GRID modeling in order to send appropriate price signals to customers, improve the accuracy of the net power cost forecast, and recognize costs and benefits not previously modeled.

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission approve the proposed GRID modeling improvements as outlined in my testimony and adopt the proposed base NPC for the test period of $1.365 billion on a total-Company basis, or $86.5 million on an Idaho-allocated basis.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Case No. PAC-E-21-07
Exhibit No. 37
Witness: Michael G. Wilding

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Michael G. Wilding

GRID Model NPC Report

May 2021

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