REDACTED
Docket No. 20000-___-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Ramon J. Mitchell

March 2023

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Ramon J. Mitchell, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Please describe your education and professional experience.

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have held various positions in the regulation, merchant, and transmission departments. After a brief departure from the Company, in 2021 I returned to the Company as Manager, Net Power Costs. In my current role I am responsible for leading and overseeing various efforts associated with the Company's net power costs ("NPC") filings.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public utility commissions in California and Oregon.

II. PURPOSE OF TESTIMONY

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

A. My testimony presents the Company's proposed NPC for the 12-month forecast period ending December 31, 2024 ("test period"); and proposes changes to the annual Energy Cost Adjustment Mechanism ("ECAM") to eliminate the sharing band. Specifically, my testimony:

- Summarizes forecasted NPC for the 2024 test period in this general rate case ("GRC") and explains the calculation of NPC using the Company's Aurora model;
- Explains the primary drivers behind the increase in NPC compared to the current base NPC approved by the Wyoming Public Service Commission ("Commission") and incorporated into customer rates in the 2020 GRC in Docket No. 20000-578-ER-20, which includes a discussion of extraordinary increases in regional power and gas market prices since the last GRC;
- Describes new and upcoming federal/state environmental compliance requirements and operations changes since the 2020 GRC that substantially impact NPC;
- Describes modeling changes the Company has made to improve the NPC forecast accuracy since the 2020 GRC; and
- Proposes elimination of the ECAM sharing band considering the Company's pending participation in an independent system operator ("ISO")-type organized market along with updated observations on trends in western markets since the last GRC.

III. SUMMARY OF COMPANY NPC

Q. How is the NPC portion of this testimony organized?

A. First, in Section III, I provide an overview of the NPC forecast for the 2024 test period. This overview includes a high-level discussion of the NPC changes since the last GRC followed by a more detailed discussion of the individual NPC components along with narrative explanations which touch on the impacts associated with new policy and operations changes.

Second, Section IV includes a discussion on the reasonableness of the NPC forecast and Section V explores in detail the drivers of regional forward power market prices and regional forward natural gas market prices which account for the majority of the change in the NPC forecast since the last GRC.

Third, in Section VI, I discuss in detail new policy and operations changes, along with the numeric impacts to the NPC forecast that each change represents.

Fourth, in Section VII, I discuss the transition from the Generation and Regulation Initiative Decision Tools ("GRID") model to the Aurora model for the forecast of NPC, then, in Section VIII I present and discuss the improvements to enhance modeling accuracy along with the numeric impacts to the NPC forecast that each improvement represents.

Fifth, in Section IX, I present a brief discussion on Situs Programs and refer to the Multi-State Process forum which is intended to resolve outstanding issues on these programs. In Section X, I present a brief summary on Company coal costs and the change in these costs between the last GRC and this current filing.

Finally, after the NPC portion of my testimony, I transition into a discussion on NPC recovery in the ECAM.

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 a subsequent ECAM filing.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for the forecast test period based on projected data using Aurora, which simulates the operation of the Company's power system on an hourly basis. The model respects all system requirements and constraints and commits and dispatches the Company's resources for a cost minimizing output where demand and supply are balanced.

Q. What Aurora inputs were updated for this filing?

A. All inputs have been updated since the 2020 GRC, including system load, reserves, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas also known as the official forward price curve ("OFPC"), fuel expenses, transmission topology, and the characteristics and availability of the Company's generation facilities.

Q. Did PacifiCorp update the regulation reserve input for this filing?

A. Yes. Consistent with past NPC forecasts, PacifiCorp has updated regulation reserves to be consistent with the latest integrated resource plan ("IRP") regulation reserve study, which is currently the 2021 IRP.

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

A. The forecast NPC used the OFPC dated December 31, 2022.

Q. What reports does the Aurora model produce?

A. The major output from the Aurora model is the NPC report. This is attached to my testimony as RMP Exhibit 10.1.

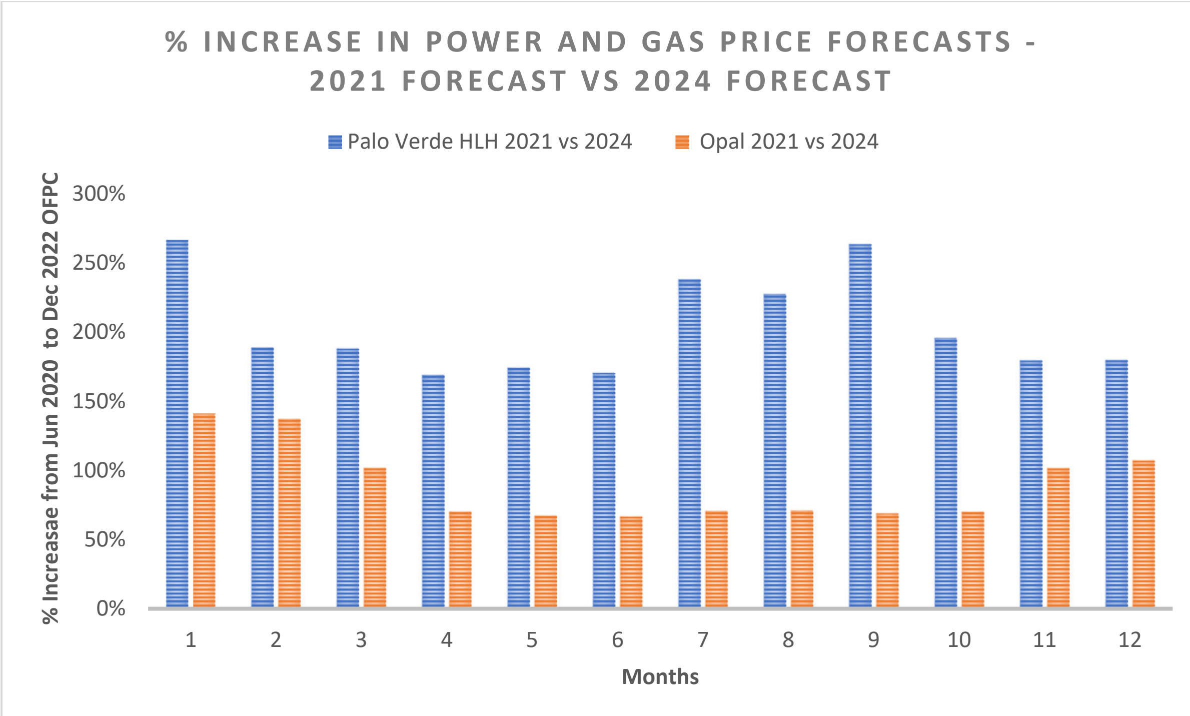
Q. What is the amount of the proposed total-Company NPC for the test period?

A. The proposed NPC for the test period are $2.553 billion on a total-Company basis and $360.3 million on a Wyoming-allocated basis. Unless otherwise noted, references to NPC or various individual cost items throughout my testimony are stated in total-Company system amounts.

Q. Please generally describe the changes in NPC compared to the 2020 GRC.

A. The NPC forecast from the 2020 GRC used a June 30, 2020 vintage OFPC to set the price expectations for a calendar year 2021 NPC forecast. Compared to calendar year 2024 price expectations from the December 31, 2022 vintage OFPC, average power market prices at the Palo Verde power trading hub increased by 199 percent and average natural gas market prices at the Opal gas trading hub increased by 89 percent as illustrated at the monthly granularity in Figure 1 below. As a result of this and four substantive changes to the 2024 landscape, which I discuss in more detail below, total-Company NPC increased by $1.122 billion or 78 percent, from a 2020 GRC forecast of $1.431 billion to this GRC forecast of $2.553 billion.

Figure 1



Q. Please explain, by line item, the changes in NPC compared to the 2020 GRC.

A. Illustrated below in Table 1 for costs and Table 2 for energy are the line item changes in NPC. Below, I expand on the individual line items.

Table 1

Net Power Cost Reconciliation ($)		
	($ millions)	**$/MWh**
WY 2020 GRC Final Forecast	**1,431**	**23.67**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(256.4)	
Purchased Power Expense	788.6	
Coal Fuel Expense	45.5	
Natural Gas Fuel Expense	514.2	
Wheeling and Other Expense	30.3	
Total Increase to NPC	**1,122.2**	
WY 2023 GRC Initial Forecast	**2,553**	**38.32**

Table 2

Net Power Cost Reconciliation (MWh)		
	MWh	**$/MWh**
WY 2020 GRC Final Forecast	**60,456,564**	**23.67**
Change to Net System Load:		
Wholesale Sales Decrease	2,359,857	
Purchased Power Increase	6,128,563	
Coal Generation Decrease	(6,609,260)	
Natural Gas Generation Increase	5,214,487	
Other Generation Decrease	(910,496)	
Total Change to Net System Load	**6,183,151**	
WY 2023 GRC Initial	**66,639,715**	**38.32**

Q. Please explain the increase in purchased power expense.

A. The purchased power expense increases in tandem with power market prices coupled with increased purchased power volumes due to lower coal generation to comply with the Ozone Transport Rule ("OTR") generation limits, the decrease in generation at the Chehalis plant due to the Washington carbon tax, the outage for Jim Bridger units 1 and 2 to complete the gas conversion, increased regulation reserve requirements and expectations of low hydroelectric generation. I explain these individual drivers in more detail, below in my testimony.

Q. Please explain the increase in coal fuel expense and the increase in natural gas fuel expense.

A. Coal generation in both Wyoming and Utah is subject to the new emissions limits in the OTR, resulting in a decrease in coal generation. The remaining coal generation shows increased expense due to increases in coal price expectations resulting from increased domestic competition for limited coal supply. Natural gas generation increases due to the gas conversion of Jim Bridger units 1 and 2 and increased dispatch of other gas units to meet load and reserve obligations left behind after the decrease in coal and hydroelectric generation. Natural gas fuel expense correspondingly increases in tandem with natural gas market prices.

Q. Please explain the increase in wholesale sales revenue and the increase in wheeling and other expense.

A. With decreased net generation, wholesale sales volume also decreases, however, the increase in power market prices increases the total revenue of the remaining sales. Wheeling expenses increase relative to the forecast in the 2020 GRC based on increases in the historical wheeling expenses supporting the 2021 and 2022 actual purchased power volumes.

IV. NPC VALIDATION

Q. Is $2.553 billion a reasonable forecast for total-Company NPC in 2024?

A. Yes. There are three layers to consider when assessing the 2024 NPC forecast: 1) historical actual NPC and the associated trend that is proportionate to regional power market prices; 2) the extrapolation of this trend using the 2024 OFPC; and 3) four upcoming, new, and substantial impacts to NPC that are not captured in the historical data or trend.

Q. Regarding the first layer, what does the historical actual NPC show?

A. There is a clear and demonstrable relationship between actual NPC and regional power market prices. First consider Table 3 below which shows, the actual 2020 NPC, the 2020 GRC forecast of 2021, the actual 2021 NPC and the actual 2022 NPC.

Table 3

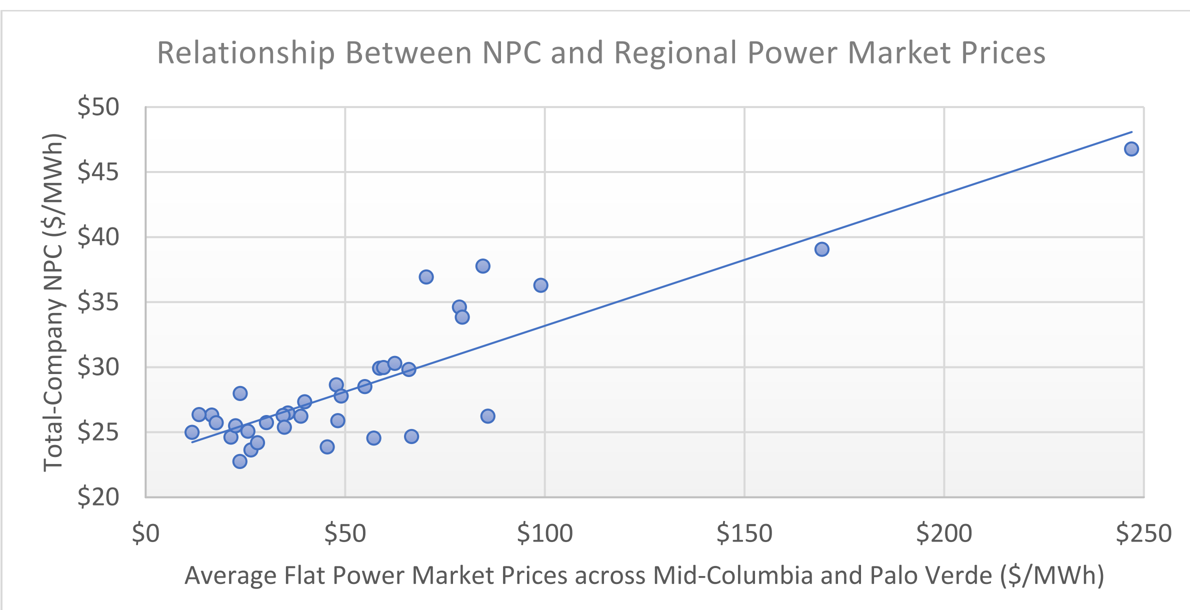
NPC Type	Total Company NPC ($)
2020 Actual	1,511,314,189
2021 *Forecast (2020 GRC)*	1,431,235,960
2021 Actual	1,714,607,879
2022 Actual	2,040,736,242

There are two items of note: 1) the 2020 GRC forecast of calendar year 2021 NPC at $1.431 billion was substantially under-forecast relative to the actual calendar year 2021 NPC, as explained in further detail below in the NPC Recovery section of my testimony; and 2) within the actuals, there is a clear upward trend in NPC.

Q. Regarding the second layer, please elaborate on this upward trend in NPC and the associated extrapolation.

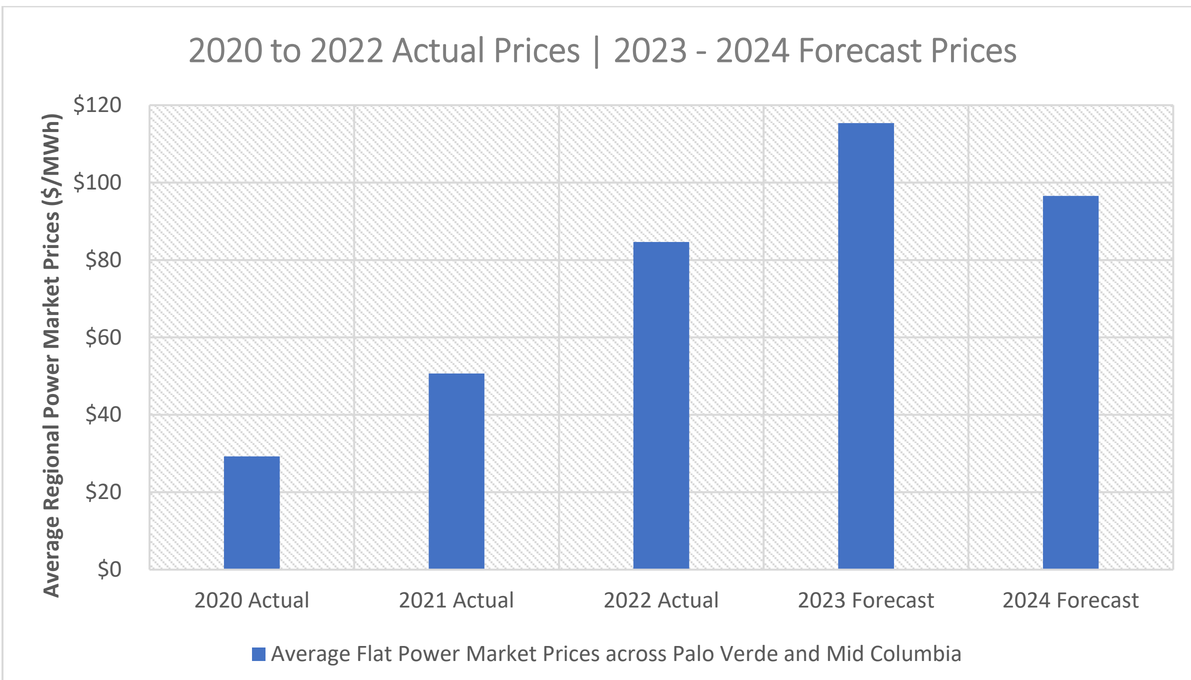
A. Breaking actual NPC down to the monthly granularity it is observed that there is a proportionate relationship between actual NPC and regional power market prices as illustrated below in Figure 2.

Figure 2



To establish a reference baseline of what a reasonable 2024 NPC forecast (without any new operational or federal/state environmental compliance requirements) might be, consider a simple extrapolation of the above relationship between regional power market prices and NPC. This extrapolation suggests 2024 NPC of $2.201 billion. Figure 3 below illustrates year-over-year changes in actual and forecast regional power market prices that provide context for the NPC increases in Table 3 and context for the extrapolation of 2024 NPC at $2.201 billion.

Figure 3



Q. Regarding the third layer, please elaborate on some of the new and upcoming operational and policy changes not captured in the historical data or the trend.

A. Historical NPC and the corresponding relationship with regional power market prices have not captured any of the cost impacts of four substantive changes to the 2024 landscape: 1) the expansion and revision of the Environmental Protection Agency's ("EPA") Cross-State Air Pollution Rule on nitrogen oxides' ("NO_x") emissions limits to encompass all generation in the states of Wyoming and Utah (also referred to as the Ozone Transport Rule or OTR); 2) the new law in Washington state that taxes greenhouse gas ("GHG") emissions through required purchases of GHG allowances (impacting the Chehalis gas-fired plant located in Washington state); 3) the conversion of the Jim Bridger power plant's units 1 and 2 from coal-fired to gas-fired units; and 4) the removal of four hydroelectric projects along the Klamath River. These four changes and their individual impacts to NPC are described in more detail, below in my testimony. In aggregate they increase NPC by $353 million.

Q. How do these three layers demonstrate the reasonableness of the NPC forecast?

A. The historical actual NPC in combination with the proportionate relationship between NPC and regional power market prices suggest that, absent any changes in policy or operations, $2.201 billion is a reasonable NPC forecast for 2024. After layering on an additional $353 million to account for the aforementioned upcoming policy and operational changes, which are not reflected in the historical data, a reasonable benchmark for 2024 NPC becomes $2.554 billion which is 0.015 percent above the proposed $2.553 total-Company NPC. This difference of 0.015 percent results from the use of a relatively simple trend analysis as a reference for the 2024 NPC (absent policy or operations changes) as compared to the more detailed simulation within Aurora.

V. REGIONAL MARKET PRICE INCREASES

Q. Why have regional power and gas market prices increased to such extraordinary highs?

A. Regional power market prices are driven primarily by regional gas market prices which are in turn driven by natural gas fuel prices. Since June 2020 (the vintage of the OFPC used in the 2020 GRC), natural gas prices have seen extraordinary year-over-year increases, as illustrated above in my testimony.

Q. Why have natural gas fuel prices seen extraordinary increases since the June 2020 OFPC?

A. The primary driver is the conflict in Ukraine which has decreased European availability of natural gas, previously sourced from Russian imports. With decreased European supply, the associated European demand has turned to U.S. domestic supply to fill the gap and the increased competition over domestic supply has driven regional natural gas fuel prices upwards with increases in domestic production yet unable to keep pace with the increased demand. This increase in natural gas fuel prices correspondingly increases regional gas market prices and regional power market prices, in that order.

Q. What other drivers impact regional power market prices?

A. Regional power market prices are lowered, on average, by increased penetration of renewable resources across the western interconnection. However, renewable resource construction across the nation has experienced delays relative to prior expectations.

Q. Why has renewable resource construction experienced delays relative to prior expectations?

A. Global supply chain constraints have delayed production and transportation of key components and equipment necessary for renewable resource construction across the nation. Furthermore, increases in the prices of key renewable resource construction commodities such as lithium, nickel and copper, as well as increases in labor costs and interest rates, exacerbate the issue.

Q. How have renewable resource construction delays impacted regional power market prices?

A. In the planning arena, at the regional level, renewable resource construction/acquisition is assumed to partially offset the impact of thermal plant retirements on an energy basis. In the short term, as the construction of these renewable resources are delayed, thermal plant retirements continue on-schedule. The resulting energy shortfall decreases supply without any associated decrease in demand (load). Consequently, this triggers an incremental energy price rise across the competitive regional power markets which is additive to the exacerbation caused by natural gas fuel price increases.

Q. Have these global events impacted coal supply and associated coal fuel prices?

A. Yes. Because of higher regional gas market prices and delays in renewable resource constructions, coal generation increases, all other things equal. This increase in the demand for coal pressures domestic coal supply in the short term resulting in higher coal fuel prices, which in turn drive regional power market prices higher. This increase in regional power market prices is additive to the increase caused by natural gas fuel price increases and additive to the increase caused by delays in renewable resource construction.

Q. Please elaborate on further drivers of regional power market price increases.

A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of the Pacific Northwest[1] and the consequent decrease in expected hydroelectric generation diminishes the expected regional energy supply.

[1] *U.S. Drought Monitor, Released Jan. 5, 2023*, NATIONAL DROUGHT MITIGATION CENTER, UNIVERSITY OF NEBRASKA-LINCOLN, https://droughtmonitor.unl.edu/.

Furthermore, calendar years 2020, 2021 and 2022 have seen an increase in abnormal/extreme weather events that have resulted in higher-than-expected load during stressed system conditions, and this trend has set expectations amongst market participants for similar conditions in 2024. Therefore, many utilities across the region have revised their expectations of load profiles upwards and this limits excess supply offered into the regional power markets.

These two weather-based drivers increase regional power market prices and both are additive to the increase caused by natural gas fuel price increases, additive to the increase caused by delays in renewable resource construction and additive to the increase caused by increased competition for coal supply.

VI. POLICY AND OPERATIONS IMPACT TO NPC

Q. What policy or operations changes are forecast to have a substantial impact on 2024 NPC?

A. There are five, which are: 1) the expansion and revision of the OTR on NO_x emissions limits to encompass all generation in the states of Wyoming and Utah; 2) the establishment of a *de-facto* tax impacting generation at Chehalis; 3) the conversion of Jim Bridger units 1 and 2 from coal-fired to gas-fired units; 4) expectations of low hydroelectric generation; 5) the construction of the Gateway South transmission line (a portion of the Energy Gateway transmission expansion), which relieves transmission limitations on the output of coal and wind generation in Wyoming.[2]

[2] The cost impacts of the Energy Gateway transmission expansion (specifically, the Gateway West Segment D.2 transmission) are not included in the analysis that demonstrates the reasonableness of the Company's proposed NPC for the test period because they are already captured in the historical data that supports that reasonability analysis.

The Ozone Transport Rule

Q. Please generally describe the OTR.

A. The EPA has established annual limits on the amount of NO_x that may be emitted by certain states inclusive of Wyoming and Utah. These NO_x limits apply during the ozone season which spans May 1st to September 30th and applies to Utah starting in 2023 and currently assumed to include Wyoming starting in 2024. The OTR is described in greater detail in the testimony of Ms. Joelle R. Steward.

Q. How did you implement the OTR in the NPC forecast?

A. Functionally, NO_x emissions limits are no different from coal contract volumetric limits, transmission capacity limits, generator capacity limits, or any of the other myriad limits inherent to the Company's operations. All Company operated gas-fired and coal-fired generation units in the states of Wyoming and Utah are now constrained by specific NO_x emissions limits across the ozone season. These unit level NO_x emissions limits are directly input into Aurora, which natively allows for this type of modeling.

Q. Ms. Steward describes the uncertainty around the implementation of the OTR, how will you manage this uncertainty in the NPC forecast?

A. The Company will update the NPC forecast pending further clarifying guidance from the EPA as and when possible.

Q. What is the impact to NPC of this policy?

A. Assuming that both Utah and Wyoming are subject to the OTR in 2024, the impact of this adjustment is an increase of $135 million. This increase is driven by increased market purchases to cover the generation reduction. Assuming that only Utah is subject to the OTR in 2024, the impact of this adjustment is an increase of $17 million.

The Washington Cap and Invest Program

Q. How does the Washington Cap and Invest ("WA-GHG") Program impact the Company's load service in Wyoming?

A. The WA-GHG program requires that the Company purchase GHG allowances for any GHG emissions output within the state of Washington for export outside the state of Washington. The only source of GHG emitting energy owned by the Company in the state of Washington is the Chehalis gas-fired plant. For all energy exported out of Washington from the Chehalis plant, there is an associated GHG cost proportionate to the energy exported. Therefore, for all energy allocated to Wyoming from the Chehalis plant, there is an incremental dollar-per-megawatt-hour ("$/MWh") cost based on the GHG allowance price for the test period.

Q. What is the GHG allowance price applied to the Chehalis plant for this test period?

A. The GHG allowance price is currently estimated at $24.75/MWh for calendar year 2024 based on an independent analysis commissioned by the state of Washington.[3] The program commences at the beginning of 2023 and the first auction will take place on February 28, 2023. The NPC forecast will be updated with refreshed prices when next possible.

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[3] WASHINGTON DEPARTMENT OF ECOLOGY, *Final Regulatory Analysis, Climate Commitment Act Program* at Page 129 (Sept. 2022), *available at* https://apps.ecology.wa.gov/publications/documents/2202047.pdf.

Q. How is the WA-GHG program similar to other Commission approved programs?

A. The WA-GHG program is a *de-facto* tax program that assesses a charge per megawatt-hour ("MWh") of energy produced from certain types of resources located in Washington state. From a cost perspective, the impact of this program on the Company's service territory is identical to the impact of Wyoming's wind tax.

Q. What is the impact to NPC of this policy?

A. The impact of this adjustment is an increase of $75 million. This increase is driven by increased market purchases to cover the generation reduction.

Jim Bridger Power Plant's Natural Gas Conversion – Units 1 and 2

Q. Please describe what is taking place at Jim Bridger units 1 and 2.

A. Jim Bridger units 1 and 2 are proposed to be converted to gas-fired units. Currently, these two units are coal-fired. The Company's proposal to convert Jim Bridger units 1 and 2 was filed in a separate application on December 9, 2022 and is a pending case with the Commission.[4]

Q. Why are Jim Bridger units 1 and 2 being converted to gas?

A. Emissions requirements imposed by the EPA required the installation of a selective catalytic reduction system to reduce NO_x emissions from Jim Bridger units 1 and 2 for continued coal-fired operations past December 31, 2023. Gas conversion was identified as a more economically viable option in the long-term analysis of the integrated resource planning process partially driven by a need for the Company to retain as much upward-dispatchable capacity as possible.

[4] *See,* In the Matter of the Application of Rocky Mountain Power for Authority to Convert the Primary Fuel Source from Jim Bridger Power Plant Units 1 and 2 from Coal to Natural Gas, Docket No. 20000-628-EA-22 (Record No. 17212).

Q. What is the impact to NPC of this conversion?

A. There are two impacts. The first impact is the result of replacing the coal-fired units with similarly sized gas-fired units, all other things equal. The impact of this adjustment is an increase of $91 million. This increase is driven by the fact that natural gas fuel is substantially more expensive than coal fuel. The second impact is the result of the outage period necessary to accomplish the gas conversion. With both units being on outage from [redacted] there is a $22 million increase to NPC. This increase is driven by increased market purchases to cover the generation.

Q. Why are the NPC impacts of the Jim Bridger units' gas conversion separated into two components?

A. The first impact is permanent and starts with a counterfactual in which the units are instantaneously converted to gas on January 1, 2024, this counterfactual is necessary due to the EPA's requirement that coal-fired operations cease on December 31, 2023. The second impact is temporary (the gas conversion process is a one-off event) and presents an isolated impact of the outage in 2024 which examines the effect of replacing gas generation with market purchases.

Hydroelectric Generation Reduction

Q. How much has hydroelectric generation decreased between the 2020 GRC and this current filing?

A. The forecast for calendar year 2024 hydroelectric generation has decreased by approximately 656,000 MWh (18 percent) as compared to the calendar year 2021 forecast from the 2020 GRC.

Q. Why has hydroelectric generation decreased by 18 percent?

A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of the Pacific Northwest[5] and is picked up in the normalized hydroelectric generation. Additionally, the pending removal of the four Company-operated hydroelectric projects[6] along the Klamath river contributes to this decrease. These projects total approximately 180 megawatts of capacity and will cease operations by the end of 2023.

Q. Did the Commission approve removal of the Klamath projects?

A. Yes. In Docket No. 20000-594-EA-21 (Record No. 15692), the Commission found that removal was a lower cost and lower risk option than relicensing. Thus, while removal creates upward pressure on NPC, it was found to be an overall prudent course of action.

Q. What is the impact to NPC of these hydroelectric projects' removal?

A. The impact of this adjustment is an increase of $42 million. This increase is driven by increased market purchases to cover the generation reduction.

Gateway South Transmission Project

Q. What is the Gateway South Transmission Project?

A. As part of the Company's Energy Gateway transmission expansion, the Company is constructing a 500-kilovolt high-voltage transmission line, known as Gateway South, extending from the Aeolus Substation in southeastern Wyoming into the Clover Substation near Mona, Utah. The Commission approved the Company's certificate of public convenience and necessity for Gateway South during public deliberations held on May 10, 2022 and construction began in June 2022 as outlined in the testimony of Mr. Rick A. Vail.

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[5] *See U.S. Drought Monitor, supra note 1.*
[6] J.C. Boyle, Copco 1, Copco 2 and Iron Gate hydroelectric projects,

Q. What are the qualitative benefits of this Gateway South transmission build?

A. The Gateway South Project will meet load growth, provide increased reliability, and improve operational flexibility in conjunction with future generation resources. Specifically, it will allow for the release of "trapped energy" from coal and wind resources in Wyoming, allowing for the deployment of additional dispatchable capacity from the aforementioned coal resources.

Q. What is the impact to NPC of the Gateway South transmission build?

A. The line is forecast to go into service in October of 2024, resulting in a decrease of $19 million, driven by increased coal and wind generation.

VII. NPC AND TRANSITION BETWEEN MODELS

Q. Did the Company transition to the Aurora model to calculate NPC?

A. Yes. The Company has used the GRID model since it was deployed in 2008 but discontinued its use for NPC filings in 2021 and transitioned to the Aurora model, produced by Energy Exemplar. Aurora provides additional functionality, increases usability, as well as increases compatibility with the Company's information technology.

To date, the Company has filed NPC forecasts using Aurora in California, Oregon, and Washington. Additionally, Aurora includes certain functionality necessary to perform the allocation of state-specific NPC for ratemaking purposes in the post-interim period as contemplated in the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2020 Protocol").[7]

[7] *See,* Application of Rocky Mountain Power for Approval of the 2020 Inter-jurisdictional Cost Allocation Agreement, Docket No. 20000-572-EA-19 (Record No. 15400).

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 general approach to the calculation of NPC is the same, but the model has changed from GRID to Aurora.

An Overview of the Aurora Model

Q. How does Aurora work?

A. Similar to GRID and other production cost models, the objective of Aurora is to meet the projected load at the lowest possible cost. This is accomplished by simulating the dispatch of available resources, both supply-side and demand-side, within their physical constraints, economic constraints, transmission constraints and emissions constraints, as well as adhering to the profiles of the load requirements to produce a cost minimizing simulation where demand and supply are balanced.

Like GRID, these simulations use input information such as system load, reserves, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, transmission topology, and the characteristics and availability of the Company's supply-side and demand-side facilities.

Q. How does Aurora compare to GRID?

A. The model logic is conceptually the same between Aurora and GRID; both models aim to minimize costs to serve obligations, under various constraints. While the categories of inputs are mostly the same between the two models, Aurora has more parameters to model resources and offers more flexibility to model more types of resources.

Q. What are some of the modeling improvements gained by moving to Aurora?

A. Aurora co-optimizes (as opposed to sequentially optimizing) energy and ancillary service requirements, allowing the model to create precise (precise in this context is different from accurate as elaborated on below in the NPC Recovery section of my testimony) NPC forecasts that simultaneously satisfies all load and reserve obligations while appropriately reflecting the forecasted costs. In addition, Aurora can receive more than one incremental price for the purpose of forecasting dispatch of coal-fired resources and can recognize and optimize around volumetric constraints in each price tier (minimum take volumes, volume limits, etc.). Furthermore, Aurora allows for the modeling of emissions constraints and associated emissions rates and emissions prices, allowing the Company to integrate compliance with various federal and state environmental compliance requirements within the model.

Q. What is the process by which the Company validated the use of Aurora as compared to GRID?

A. Both GRID and Aurora are production cost optimization models that use mathematical optimization techniques with similar inputs that attempt to satisfy the Company's load and reserve obligations at minimum cost. Aurora has more features and flexibility, but both models are based on the same underlying economic principles. The validation process started with the understanding that the results from the two models will be different. Based on that understanding, the process included steps such as: 1) verify if the outputs of non-dispatchable resources match the inputs, and the outputs match between Aurora and GRID; 2) refine input parameters in Aurora that are either not available in GRID or have a different impact on optimization; and 3) research the reasons why the same dispatchable resources with generally the same inputs produce different results from Aurora and GRID. And, finally, the total NPC from the two models are compared and reviewed for reasonableness which includes ensuring that the deviation in the total NPC is within a reasonable range.

Q. Why would the same resources produce different results from Aurora and GRID when they have the same inputs?

A. The inputs in the two models are not the same because Aurora allows for more modeling parameters and more levels of granularity. Additionally, Aurora co-optimizes energy and ancillary service requirements by using an advanced mixed integer program, whereas GRID sequentially optimizes one requirement then the other. Furthermore, Aurora uses its mixed integer program for commitment (startup/shutdown) decisions whereas GRID applies relatively basic static optimization techniques. Differences in the optimization techniques lead to different unit commitments and different unit dispatches based on the prevailing economics.

Q. Can you provide the results of the Company's validation process?

A. Yes. Please refer to RMP Exhibit 10.2 and RMP Exhibit 10.3, which contain the Aurora and GRID NPC test reports that the Company used to validate the Aurora model. The test reports show that there was less than 0.8 percent variation between the NPC calculated with GRID as compared to Aurora.

Q. While the overall variation was low, there may have been greater variation in individual resources when comparing the two test reports. Can you comment?

A. Yes. As I discussed above, there are differences between Aurora and GRID with regards to optimization techniques. In addition, each model contemplates different levels of granularity of inputs. Those two in combination will result in different dispatch of resources, and different balancing transactions. Therefore, the validation process compared the overall outcome of the NPC test report.

Q. Would running GRID with the inputs used for this rate case provide additional useful information regarding the validation of the Aurora model?

A. No. As described above, the ability of each model to accept different inputs and the internal optimization techniques differ between the models even though the underlying principles are similar. Furthermore, there are inputs in Aurora that are not capable of being accepted by GRID (example, emissions constraints and tiered price/volume coal contracts). There is no reasonable expectation that the model results would be the same or would provide additional insight, making the proposed comparison a futile exercise. Additionally, the Company has already benchmarked Aurora against the GRID model and found that the overall NPC results exhibited a tolerable variance between the two models when limiting the inputs to those capable of being simultaneously accepted by both models.

Inputs and Adjustments in Aurora

Q. How are inputs treated differently between the two models?

A. Aurora incorporates many of the same inputs that GRID formerly considered in its optimization. Consequently, many of the same workpapers are still in use, but those inputs flow through Aurora input workbooks to be formatted for acceptance by the newer model. For inputs that are quite distinct from their GRID equivalents (coal prices, for example), entirely new modeling approaches were employed to take advantage of the additional flexibility offered by Aurora. There are also inputs that are the same but require slightly modified calculations to account for the treatment given to those inputs in Aurora (unit minimum operating levels and thermal outage rates, for example).

Q. How is the output from Aurora incorporated into Wyoming-allocated NPC?

A. The Aurora model results are used to create a total-Company NPC forecast and the total-Company NPC report is similar to the report that has been used in the past. Those results are then allocated according to the 2020 Protocol to arrive at a Wyoming-allocated NPC forecast.

Q. Please describe any other significant modeling differences between GRID and Aurora?

A. As mentioned above, Aurora accounts for unit minimum operating levels ("unit minimums") and equivalent outage rates ("EOR") differently, and both required formulaic updates because of differences in the modeling of unit availabilities. Aurora scales both the unit maximum capacity and the unit minimum in response to a derate because Aurora requires unit minimums to be expressed as a percentage of unit maximum capacity. In GRID, unit minimums were required to be expressed in absolute megawatt amounts. Prior to settling upon a revised approach to the calculation of these inputs, the Company observed many hours where the generation forecast showed output below a unit's minimum. A relatively straightforward solution was adopted by the Company that only required the calculation and input of an hourly unit minimum percentage (percentage of unit capacity) timeseries to account for derates. To avoid the possibility of infeasible operations, another modification was made to the EOR to remove units from service (that is, the EOR was set to 100 percent) whenever the available capacity slipped below the unit minimum. In addition, Aurora can receive more than one incremental price for the purpose of forecasting dispatch of coal-fired resources and can recognize and optimize around volumetric constraints in each price tier (minimum take volumes, volume limits, etc.). That modeling improvement allows the Company to more easily arrive at a forecast of coal unit dispatch that is subject to volumetric constraints and tiered pricing across a range of consumption levels.

Q. Is the Day-Ahead/Real-Time ("DA/RT") Adjustment needed in Aurora?

A. Yes. The DA/RT adjustment is used to better reflect system balancing costs that are not fully captured in the Aurora model. This adjustment indicates a deviation of actual market prices available to the Company in real operations from the historical monthly trading-hub-indexed market prices. The DA/RT adjustment is the result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

To better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes separate prices for forecast system balancing sales and purchases in Aurora. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market-indexed prices.

Additionally, like GRID, the volume of system balancing transactions generated by Aurora is smaller than the volume of similar transactions in actual results. Because Aurora balances the Company's load and resources to fractions of a megawatt for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a quarterly, monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that approximately half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position in real-time.

Finally, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker.

VIII. MODELING IMPROVEMENTS TO THE NPC FORECAST

Q. Why are modeling improvements necessary?

A. Modeling improvements align the NPC forecast with operational realities and make best efforts to hold true to the ECAM sharing band incentive for modeling accuracy, particularly in the current environment of recent NPC under-forecasts as explained in further detail below in the NPC Recovery section of my testimony.

Q. What modeling improvements have been implemented since the 2020 GRC?

A. The Company has incorporated the following improvements since the last rate case:

- The DA/RT market price adder will be changed from a flat value to a percentage.

- Trapped energy will be appropriately substituted for curtailment of generation to reflect actual operations.
- The maximum capacity of certain thermal generation units will be updated to reflect ambient temperature derates to unit capacity during the summer months.

DA/RT Adjustment - Price Component

Q. Please explain how the price component of the DA/RT adjustment operates.

A. The price adder component of the DA/RT adjustment addresses the costs incurred by the Company as a result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

To better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes separate prices for forecast system balancing sales and purchases in Aurora. These prices account for the historical price differences between the Company's purchases and sales compared to the trading-hub-indexed market prices. Previously these prices were calculated by adding or subtracting a flat dollar amount to the hourly scaled prices from the OFPC.

Q. Please explain how changing the DA/RT adjustment price component from a flat value to a percentage of market price results in a DA/RT adjustment that is more reflective of actual operations.

A. Changing the price calculation to a percentage of the market prices aids in accounting for the volatility caused by prices and system conditions not captured in day-ahead transactions. Take, for example, a $5 price adder in an hour when the market price is $25. This resolves to a 20 percent price adder. But using the $5 price adder when market prices are $75 would fail to account for the system and market conditions during that hour. Using a 20 percent price adder during hours when market price is $75 would yield in a $15 price adder which is more reflective of the system conditions. A key benefit of using a percentage adder is that it allows the modeling to capture intra-month variability. Consequently, this is a more accurate representation of real operating conditions experienced by the Company.

Q. Please quantify the impact of this adjustment.

A. The impact of this adjustment is an increase of $11 million to NPC. The primary driver for this change is the captured effect of intra-month market volatility on market transactions.

Trapped Energy

Q. Please explain the Company's trapped energy concept.

A. Primarily, trapped energy is a modeling concept only and does not exist in actual operations. It represents any excess generation that cannot be used to serve load due to transmission constraints or system-level oversupply. Because of limited transmission and the need for supply and demand to always be balanced, the trapped energy is captured within a modeled trapped energy zone and serves "pseudo load" that is regulated by a "pseudo generator" with an infinite ramp rate ("pseudo" - i.e., the load and generation in the trapped energy zone are also modeling constructs that do not exist in actual operations).

Q. Why was the trapped energy modeling concept necessary in GRID?

A. Conceptually, the trapped energy zones allow for a feasible model solution in the event of an inability to maintain the supply/demand balance when there is excess supply

However, the primary function of trapped energy zones in prior GRID NPC simulations was to allow for Company-owned production tax credit ("PTC") eligible wind to be modeled with a reasonable degree of accuracy. Due to an inability in GRID to model resources with a negative dispatch price (representative of PTCs, in the case of wind), these wind resources could not provide the proper price signal to the model and therefore could not be accurately represented within GRID's resource stack. As a work-around, the wind resources were simulated as must run resources and all excess wind generation within a transmission constrained area was funneled into a trapped energy zone.

Q. How was energy in the trapped energy zone valued?

A. In the past, the Company valued trapped energy at 75 percent of market prices, which led to overstated sales revenue. Since this trapped energy concept does not exist in actual operations, the value of trapped energy should be zero.

Q. How does Aurora eliminate the need for trapped energy zones?

A. Aurora allows for wind curtailment while recognizing the PTC benefits that produce an implied negative dispatch cost. By placing the wind resources at the bottom of the resource stack and allowing the model to dispatch the wind resources downwards when there is more energy from the wind resources than there is transmission to move the energy to load, or when the ramp capability of dispatchable resources are unable to follow the hour-to-hour ramps in wind generation, the NPC simulation dispatches (curtails) the wind downwards and appropriately reflects how wind resources are actually operated and actually dispatched downwards in actual operations.

Q. Please quantify the impact of allowing wind to be curtailed in similar fashion as actual operations.

A. The impact of allowing for realistic wind curtailment is an increase of $49 million driven by: 1) a reduction in pseudo-wholesale sales revenue earned from the sales of energy derived from a modeling construct that does not exist in actual operations; and 2) incremental wind curtailments to maintain the supply/demand balance within a transmission congested region when considering that any sharp hour-to-hour ramps in wind generation are unable to be completely balanced by relatively slow ramping coal units present in the region.

Q. Please quantify the impact of valuing the trapped energy zone at zero percent of market prices after allowing for wind curtailments.

A. The impact to NPC is $0 since after allowing for appropriate wind curtailment the trapped energy modeling construct has been removed. That is to say, there are no more trapped energy zones modeled in this filing.

Thermal Attributes

Q. What updates did the Company make to the characteristics of some of its thermal resources?

A. Thermal plant capacities have been previously calculated as the average of historical capacity over general summer and winter periods. For some thermal plants, performance decreases as the ambient temperature increases. As temperatures are historically hotter during the summer months of June through September, the generation output from these thermal plants decreases during those months. To account for this operational constraint, the Company updated the maximum capacities at certain plants during each summer month from June through September.

Q. Please explain how this adjustment results in more accurate forecast NPC.

A. Because maximum capacities of some thermal plants are reduced as a result of increased temperatures in the summer, not adjusting the capacity during the summer months based on these conditions would result in Aurora overstating plant capacity and generation output, which would consequently understate the need to dispatch higher cost units or increase purchases to serve load during the summer months. Reducing generation capacity during summer based on average summer temperatures is reflective of actual ambient-temperature constraints.

Q. Please quantify the impact of this adjustment.

A. The impact of this adjustment is an increase of $18 million. This increase is driven by increased market purchases.

IX. SITUS PROGRAMS

Q. What are Situs Programs?

A. Situs Programs are programs under which resources are acquired by the Company in response to state or customer specific initiatives or requirements.

Q. How are these programs and associated resources relevant to this filing?

A. The after-the-fact cost adjustments made to these programs within the ECAM were non-precedentially settled under an agreement that these adjustments will be addressed in a future GRC or through the Multi-State Process ("MSP").[8]

[8] *In the Matter of the Application of Rocky Mountain Power to Increase Current Rates by $27.8 million to recover deferred net power costs under Tariff Schedule 95 Energy Cost Adjustment Mechanism*, Docket No. 20000-617-EM-22 (Record. No. 17037), Memorandum Opinion, Findings, and Order Approving Stipulation at Appendix A, ¶2 (Feb. 15, 2023).

Q. How are these adjustments being addressed?

A. As contemplated in the settlement agreement, discussions on these after-the-fact adjustments are underway in the MSP.

Q. How are these Situs Programs reflected in the NPC forecast?

A. Situs resources are not included in the modeling of forecast NPC except for certain Utah Schedule 34 resources which are accompanied by new load.

X. SUMMARY OF COMPANY COAL COSTS

Q. How does the Company plan to meet fuel supplies for its coal-fired plants in 2024?

A. The Company employs a diversified coal supply strategy, with [redacted] percent of its 2024 coal requirements supplied by third-party coal supplies and [redacted] 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.

Q. Please generally describe the coal supply arrangements across the Company's coal-fired plants for 2024.

A. The following Confidential Table 4 summarizes the coal supply arrangements and costs for 2024 in comparison to the 2020 GRC:

[redacted]

[redacted]

Q. Please describe the changes in the Company's coal costs for 2024.

A. As discussed earlier in my testimony, increased regional natural gas fuel prices, the corresponding increase in *regional* coal generation observed now, and the associated increased competition for regional coal supply has contributed to an increase in coal fuel prices. In addition, higher than average inflation has impacted many of the coal supply agreements that are subject to market-based price adjustments. Due to these and other factors, coal costs for 2024 have increased to $632 million. This represents an increase of $46 million or 8 percent relative to the 2020 GRC.

XI. NPC RECOVERY

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

A. In this section of my testimony, I explain the Company's proposal to eliminate the ECAM sharing band.

Q. How is this section organized?

A. First, I provide an overview of the current ECAM with a focus on the sharing band and present the Company's proposal to eliminate the sharing band considering developments since the last 2020 GRC, including the Company's upcoming participation in the Extended Day Ahead Market ("EDAM") and the challenges of accurately forecasting NPC.

Second, I explain what the EDAM is and discuss how the Company's participation in the EDAM, an ISO-type organized market, warrants the elimination of the ECAM sharing band. Specifically, I present the benefits of the EDAM and discuss how the cost control objective of the ECAM sharing band is simultaneously achieved and no longer relevant as a direct consequence of EDAM participation.

Third, I address how the evolving energy industry's landscape makes it near impossible to model forecasted NPC accurately. The drivers of this diminished model accuracy are shown to be ongoing and recent increases in region-wide adoption of weather dependent generation and the associated impacts to the prices observed in the regional forward power markets. Additional discussion on the asymmetry in the region-wide supply stack that results from weather dependent generation provides further support for continued expectations of diminished model accuracy.

Fourth, in support of the conclusions I reach regarding modeling accuracy, I demonstrate how the accuracy of the regional forward market prices that support the NPC forecast model has deteriorated over time since the 2020 GRC. I explain that NPC variances can be negative or positive and the associated degradation in modeling accuracy can result in either substantial over-recovery or substantial under-recovery.

Finally, I discuss how the as-designed objectives of the ECAM sharing band are either being achieved absent the sharing band or unachievable with or without the sharing band.

Overview of the ECAM and the Company's ECAM Proposal

Q. Please describe Wyoming's ECAM.

A. The ECAM is a rate making mechanism, filed on an annual basis, through which the Company returns to or recovers from customers the difference between Wyoming-allocated actual NPC that occur during the prior calendar year and the base (forecast) NPC that are approved by the Commission in a general rate case. The ECAM also includes return or recovery of certain other non-NPC items that were approved by the

Commission as further outlined in tariff Schedule 95.[9] The variance (positive or negative) between actual NPC and the forecast NPC embedded in rates are subject to a sharing band.

Q. Please explain the sharing band.

A. A majority of the ECAM items are subject to a symmetrical sharing band where the Company returns to or recovers from customers 80 percent of the difference between actual and forecast ECAM costs, and the remaining 20 percent of the difference is retained or absorbed by the Company ("80/20 sharing band"). However, in the 2020 GRC the Commission approved including PTCs in the ECAM that are not subject to the sharing band and are returned to customers at 100 percent of their value.[10]

In the 2022 ECAM,[11] actual NPC accounted for 98 percent of all actual costs subject to the sharing band and consequently serves as the focus of this discussion.

Q. What change is the Company proposing to the ECAM?

A. The Company proposes to eliminate the ECAM 80/20 sharing band to allow for 100 percent return to or recovery from customers for the mechanism's revenues or costs.

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[9] *See* PSC No. 17, Rocky Mountain Power Schedule 95, Energy Cost Adjustment Mechanism, *available at* https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf; *See also*, Docket No. 20000-469-ER-15 (Record No. 14076). Memorandum Opinion, Findings of Fact, Decision and Order (Dec. 30, 2015). The Commission approved the inclusion of chemical costs and coal generation start-up fuel costs since they are closely related to NPC.

[10] *See*, Docket No. 20000-578-ER-20 (Record No. 15464), Memorandum Opinion, Findings and Order (July 15, 2021). The Commission approved a change to the sharing band and the inclusion of production tax credits that are not subject to the sharing band.

[11] For Calendar Year 2021, Docket No. 20000-617-EM-22 (Record No. 17037).

Q. What was the purpose of the ECAM sharing band?

A. When the ECAM was implemented in 2010, the Commission concluded that the "ECAM should be structured to provide incentives to the Company for four purposes: [i] to use the existing forecasting mechanisms; [ii] to encourage the accuracy of modeling supporting the forecasts; [iii] to avoid creating commercial disadvantage to roughly 70 percent of RMP's load in Wyoming, which would ultimately be detrimental to all Wyoming customers; and [iv] to encourage the Company to use its best efforts to control costs."[12] To accomplish these objectives, the ECAM was structured with a sharing band.

Q. When did the Commission last adjust the ECAM sharing band?

A. The Commission last adjusted the ECAM sharing band in the 2020 GRC[13] moving it from 70/30 to 80/20.

Q. What changes have taken place since the 2020 GRC to support eliminating the sharing band?

A. Since the 2020 GRC there have been two major changes: The first change is that in December 2022, the Company announced its intention to join the EDAM,[14] which will create efficiencies that reduce NPC. As explained in more detail below, once the EDAM is operational in 2025 the Company will no longer control the economic dispatch of its resources, which means a majority of NPC will no longer be under the Company's direct control.

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[12] *See* Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order (Feb. 4, 2011).

[13] *See* Docket No. 20000-578-ER-20 (Record No. 15464), Memorandum Opinion, Findings and Order (July 15, 2021).

[14] *PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market* (Dec. 8, 2022), News Release*, available at* https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html.

Second, the accuracy of modeling underlying the NPC forecasts continues to exhibit a substantive trend of deterioration despite the ECAM intended incentive to encourage the accuracy of modeling. This deterioration results from an increase in the inaccuracy of regional forward market price expectations.

The Extended Day Ahead Market

Q. What is the EDAM?

A. The EDAM is an initiative by the California Independent System Operator ("CAISO") to extend participation of a developed organized day-ahead, hour-ahead and intra-hour market to the region. The EDAM will provide economically optimal and least-cost, resource schedules, startup/shutdown instructions, and other core functions integral to organized markets across the footprints of ISOs and regional transmission organizations.

Q. What are the benefits to customers of EDAM Participation?

A. Customers will see lower actual NPC resulting from EDAM participation with preliminary analysis suggesting that annual NPC across the EDAM footprint may decrease by approximately $543 million.[15] Through the EDAM, the Company's generation units will be optimally scheduled and dispatched using the CAISO's state of the art unit commitment and economic dispatch models. Additionally, the EDAM's automated, expanded footprint and optimized dispatch will replace the Company's isolated dispatch within its two balancing authority areas. Participation in the EDAM will benefit customers by reducing NPC through more efficient and economic dispatch, inter-regional transfers (i.e., exports and imports between EDAM participants), GHG

[15] CAISO EDAM Benefits Study, CALIFORNIA ISO (Nov. 4, 2022), *available at* http://www.caiso.com/Documents/Presentation-CAISO-Extended-Day-Ahead-Market-Benefits-Study.pdf.

revenue, and reduced reserve requirements, with relatively low ongoing operation costs, very similar to the benefits of the Energy Imbalance Market ("EIM") but larger in scope.

Q. How is the EDAM related to the EIM?

A. Whereas the EIM is the extension of an organized, intra-hour market to the region by the CAISO, the EDAM is similar in concept but larger in scope and applies to the day-ahead, hour-ahead and intra-hour timeframes (i.e., EIM participation is required for EDAM participation and therefore the EDAM replaces the EIM). The combination of the EDAM and the EIM create a complete organized market.

Q. How, specifically, is the EDAM larger in scope than the EIM?

A. The EIM is an intra-hour market that dispatches a portion of the Company's total generation and executes market transactions to maintain intra-hour supply-demand balance.

The EDAM is a day-ahead, hour-ahead and intra-hour market (a complete organized market) that will dispatch the entirety of the Company's total generation on a day-ahead basis, and again on an hour-ahead basis, and again intra-hour, while executing market transactions to maintain supply-demand balance across all three timeframes (day-ahead, hour-ahead and intra-hour).

Q. How have customers benefited from the EIM since the Company's participation in 2014?

A. Since the inception of the EIM, the Company's customers have enjoyed savings of and reduction to NPC of $591 million.[16] Initial estimates show that participation in the

[16] *Western Energy Imbalance Market Benefits as of 1/1/2023,* CALIFORNIA ISO, *available at* https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

EDAM will provide even greater benefits. However, participating in the EDAM also allows an ISO to economically control and optimize a larger portion of the system.

Q. How does operation in the EIM currently affect the Company's economic control of NPC?

A. Without consideration of hedging transactions or long-term power/fuel contracts, through participation in the EIM, the Company still retains economic control over a majority of NPC. Although the EIM provides more economically efficient intra-hour dispatch, only a portion of the Company's total generation output and market transactions are optimized by the EIM. This is because intra-hour dispatch responds only to intra-hour changes in the net load (load less wind less solar) profile and these intra-hour changes in the net load profile are only an increment to the day-ahead and hour-ahead timeframes which, absent the EDAM, are economically controlled and optimized by the Company.

Q. Once the EDAM is operational, how will EDAM operation affect the Company's economic control over NPC?

A. The EDAM will economically control and optimize most of the day-ahead, hour-ahead and intra-hour Company generation and market transactions. This is a majority of NPC (without consideration of hedging transactions or long-term power/fuel contracts) because transactions before the day-ahead timeframe are mostly hedging transactions along with resource sufficiency transactions[17] and reliability-related activities.[18]

[17] Bilateral transactions required to demonstrate resource adequacy in the day-ahead timeframe.
[18] An example would be responding to unplanned outages/derates and scheduling planned outages/derates.

Q. Why are hedges or long-term contracts not considered in assessing the scope of the EDAM?

A. Hedging transactions and associated costs are designed to limit the risks and variability associated with market exposure and provide rate stability; they are not economic optimization transactions. Long-term contracts are typically either qualifying facilities and their associated generation (which the Company must purchase), purchased power agreements (which are few in number and easily accessible for prudency review), or coal supply agreements (which are tabulated above in my testimony).

Q. Given the Company's decision to participate in the EDAM, what does this mean for the Company's ability and incentivization to lower NPC?

A. As a result of the decision to participate in the EDAM, the economic operations of the Company's system on a day-ahead, hour-ahead and intra-hour basis will be managed by an ISO whose mandate is to leverage state of the art optimization software to minimize power costs for all market participants. Under this paradigm, the majority of the Company's NPC will be driven as low as the EDAM can achieve and, simultaneously, out of the Company's control.

Q. One of the Commission's stated objectives for the ECAM is to encourage the Company to use its best efforts to control costs. With participation in the EDAM, do you believe the Company would meet this objective without the sharing band?

A. Yes. When the Commission rendered its decision in the original ECAM and established a sharing band, the Company did not participate in an ISO-type organized market. With participation in the EDAM, the majority of NPC will no longer be under the Company's direct economic control but will instead be optimized by the ISO using state of the art optimization software to minimize NPC. Accordingly, the Company will control costs by participating in the EDAM, not by minimizing costs through the day-ahead, hour-ahead, and intra-hour transactions that the Company controlled when the ECAM was created. In other words, when the economic control of NPC is simultaneously taken out of the Company's hands and guaranteed, by an independent third-party, to be as low as modern optimization techniques can achieve, there are very few cost controls left for the ECAM sharing band to incentivize.

Q. What are the implications to cost recovery from participation in a complete organized market?

A. In and of itself, participation in a complete organized market, overseen by an independent third-party operator and monitored for efficiency by an independent market monitoring agency, merits 100 percent recovery of NPC because the market structure itself guarantees lower actual NPC through independent, automated, least-cost commitment and dispatch of the Company's system in the day-ahead, hour ahead and intra-hour timeframes.

Supplemental and concurrent to this fact, is the ever-growing difficulty of the Company to accurately forecast NPC based on shifting regional dynamics as discussed in the following sub-section.

Modeling Accuracy

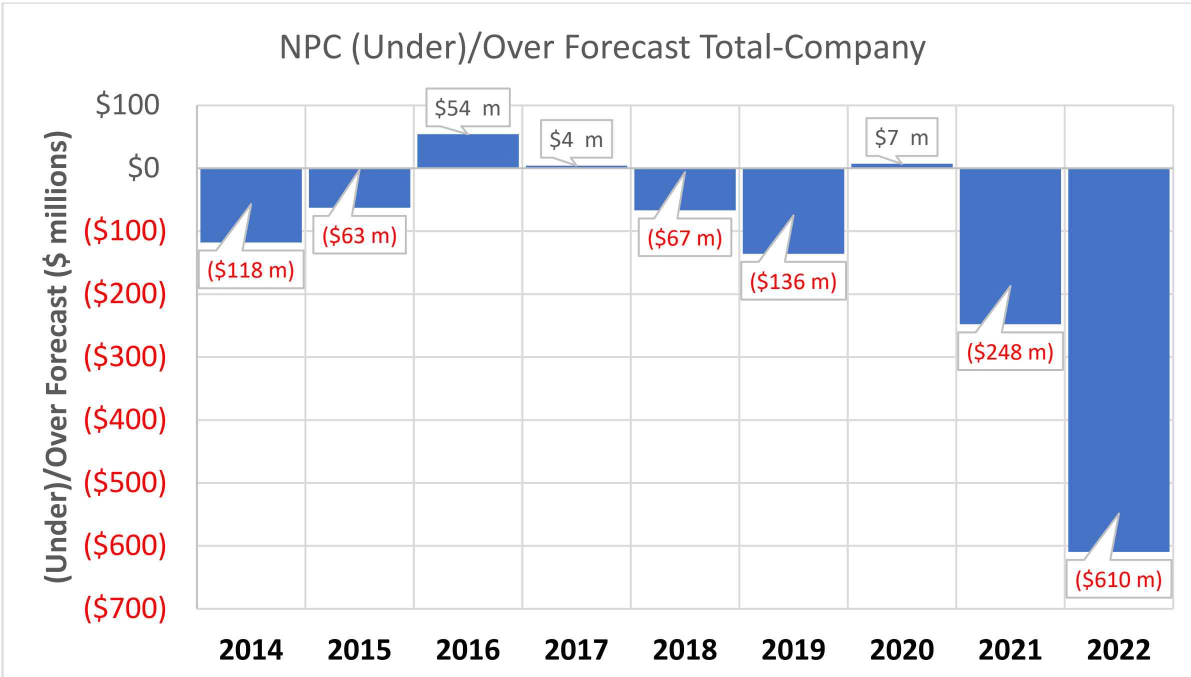
Q. How has the Company's forecast NPC compared to actual NPC in recent years?

A. Figure 4[19] below is a comparison of forecast (base) Wyoming NPC to actual NPC at the total-Company level and demonstrates that there has been substantial exacerbation

[19] The 2022 variance is a comparison between unadjusted (as opposed to adjusted) actual NPC and base NPC. All other variances are total-Company variances from direct ECAM filings.

of NPC variance in recent years. Negative numbers in Figure 4 indicate that actual NPC were greater than forecast NPC.

Figure 4



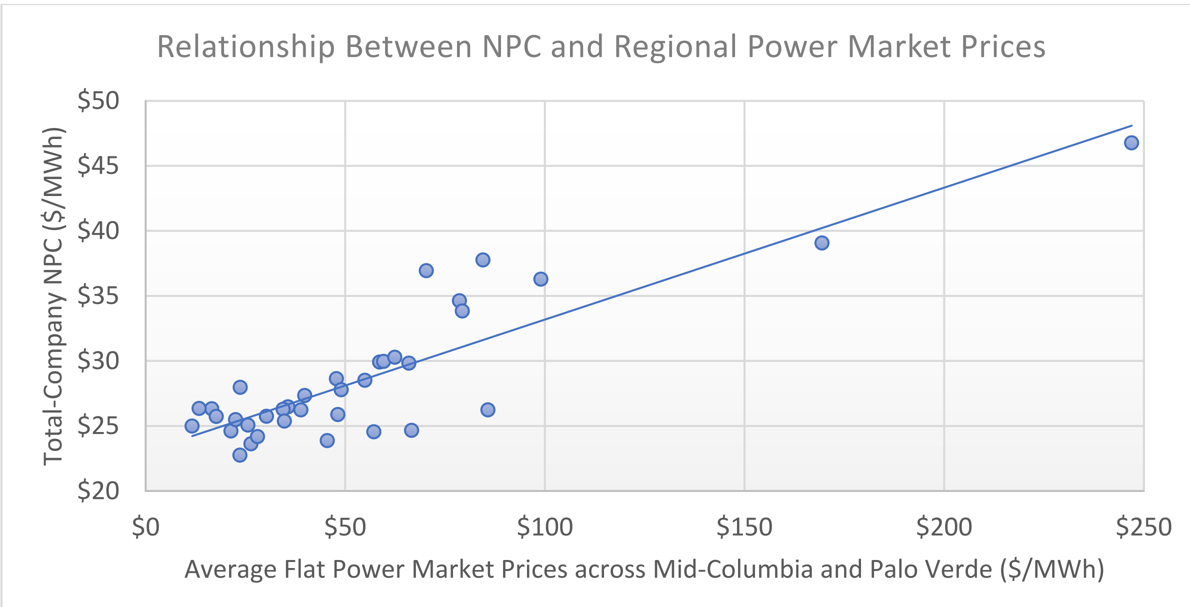
Q. One of the Commission's stated objectives for the ECAM is to encourage the accuracy of modeling supporting the forecasts. Why has the NPC forecast accuracy not improved over time?

A. NPC forecasts are less accurate, in part, because regional forward power market price forecasts in the western interconnection have become less accurate, which is particularly problematic given that NPC forecasts rely on regional market price forecasts that are often developed one to two years before rates are effective (for example, the NPC forecast in this case was based on forward prices from December 2022; by the end of the 2024 test period, the forward price forecast will be two years old). In prior decades, these forecasts were *relatively* stable, but, in recent years these forecasts have become less accurate, as I describe in more detail below and as indicated in Figure 4 above.

Q. What is the relationship between NPC and regional power market prices?

A. NPC are driven by and are proportionate to regional power market prices as re-illustrated below in Figure 5.

Figure 5



Q. How are regional power market price forecasts developed?

A. Regional power market price forecasts for one to three years out (the prices used in the official forward price curve) are actual market prices in the actual forward power markets within the western interconnection. These prices are not created by the Company but are determined by the aggregate trading activity of all regional market participants.

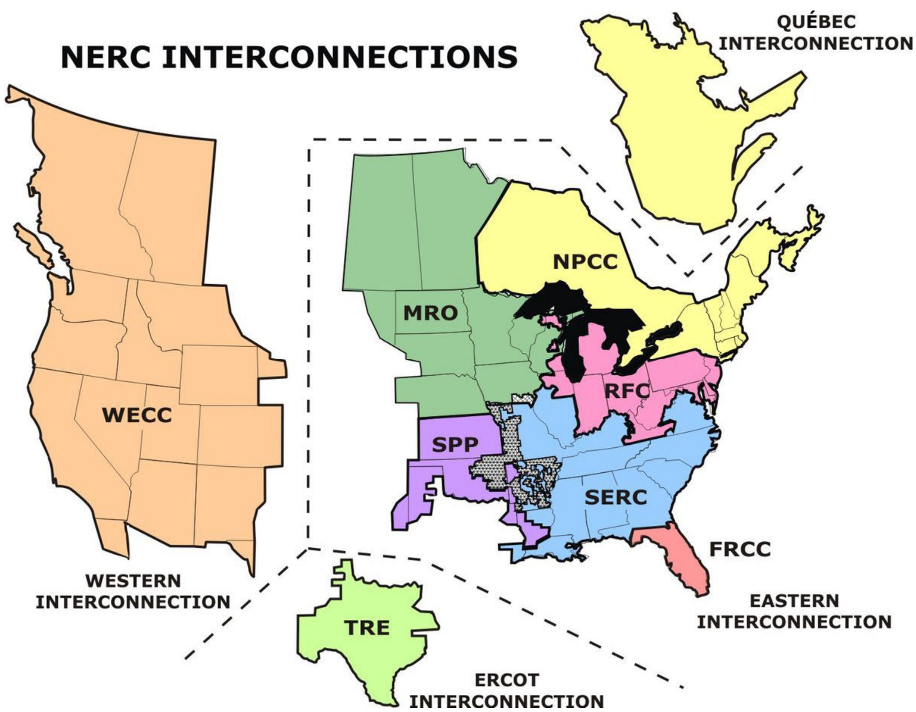
Q. What is the western interconnection?

A. Please refer to Figure 6 below. The western interconnection is the geographic area containing the synchronously operated electric grid in the western part of North

America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta.[20]

Regional power market prices are based on the supply and demand across the entirety of the western interconnection, subject to transmission limitations. Other interconnections play a limited to negligible role in regional power market prices given the limited transmission connectivity between interconnections.

Figure 6

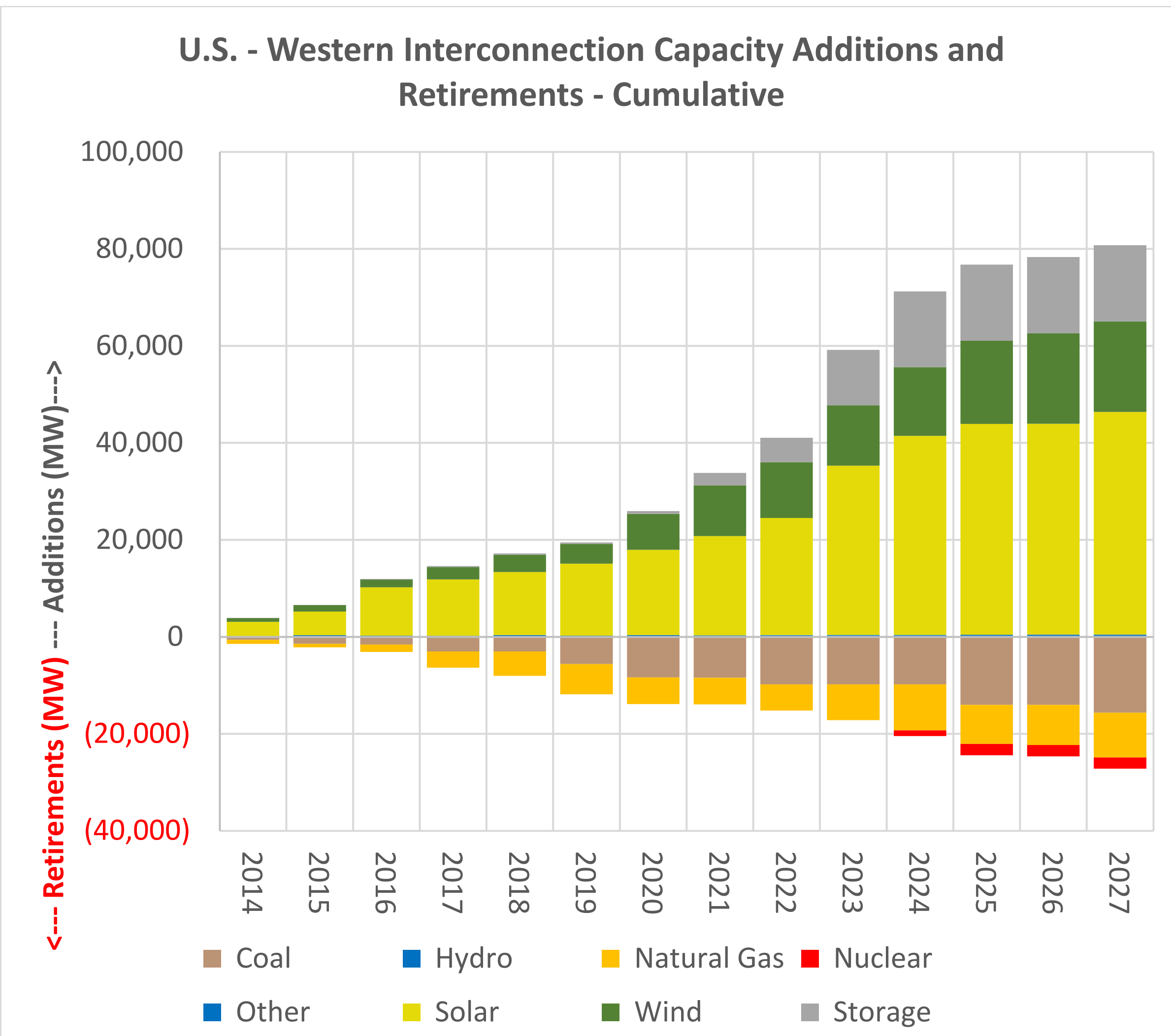


[20] *The Western US Power System*, TRANSMISSION AGENCY OF NORTHERN CALIFORNIA (accessed Feb. 23, 2023), https://www.tanc.us/understanding-transmission/the-western-us-power-system/.

Q. Why have regional power market price forecasts in the western interconnection become less accurate in recent years?

A. The resource mix across the western interconnection has evolved from one dominated by controllable thermal generation to one dominated by intermittent weather-dependent generation. Specifically, coal and gas generation facilities are being retired and replaced with solar and wind generation facilities. Figure 7 below illustrates this year-over-year change in the western interconnection's resource mix.

Figure 7



Q. Are these resource mix changes in the western interconnection a consequence of, or driven by, the Company's decisions?

A. No. The Company's portfolio of wind and solar resources is only approximately four percent of the total wind and solar capacity across the western interconnection. Had the Company not installed a single megawatt of wind or solar generation, the NPC forecast would still be driven by market prices and, therefore, still suffer from difficulties in forecast accuracy resulting from the region-wide adoption of these weather dependent resources.

Q. Why has the change in resource mix within the western interconnection decreased NPC forecast accuracy?

A. Current forecasting techniques are incapable of accurately predicting the weather one to two years out into the future. For example, the wind speeds across the western interconnection during the month of February in 2024 are impossible to predict with any reasonable degree of accuracy on the day that this testimony was filed in March of 2023.[21] Using the Pacific Northwest as an example, wind generation changes are correlated with regional power market price changes and consequently, any material variance in wind generation from forecast to actual corresponds to a material variance in regional power market prices, from forecast to actual.

Consequently, as the resource mix in the western interconnection becomes more dominated by generation that is dependent on wind speed and solar irradiance (sunshine), the regional power market price expectations for one to two years out become less accurate. As previously illustrated in Figure 5 above, any material change

[21] Across an annual period, average wind speed forecasts are borderline reasonably accurate. At more detailed levels of granularity, for example monthly or hourly, these forecasts do not exhibit reasonable levels of accuracy.

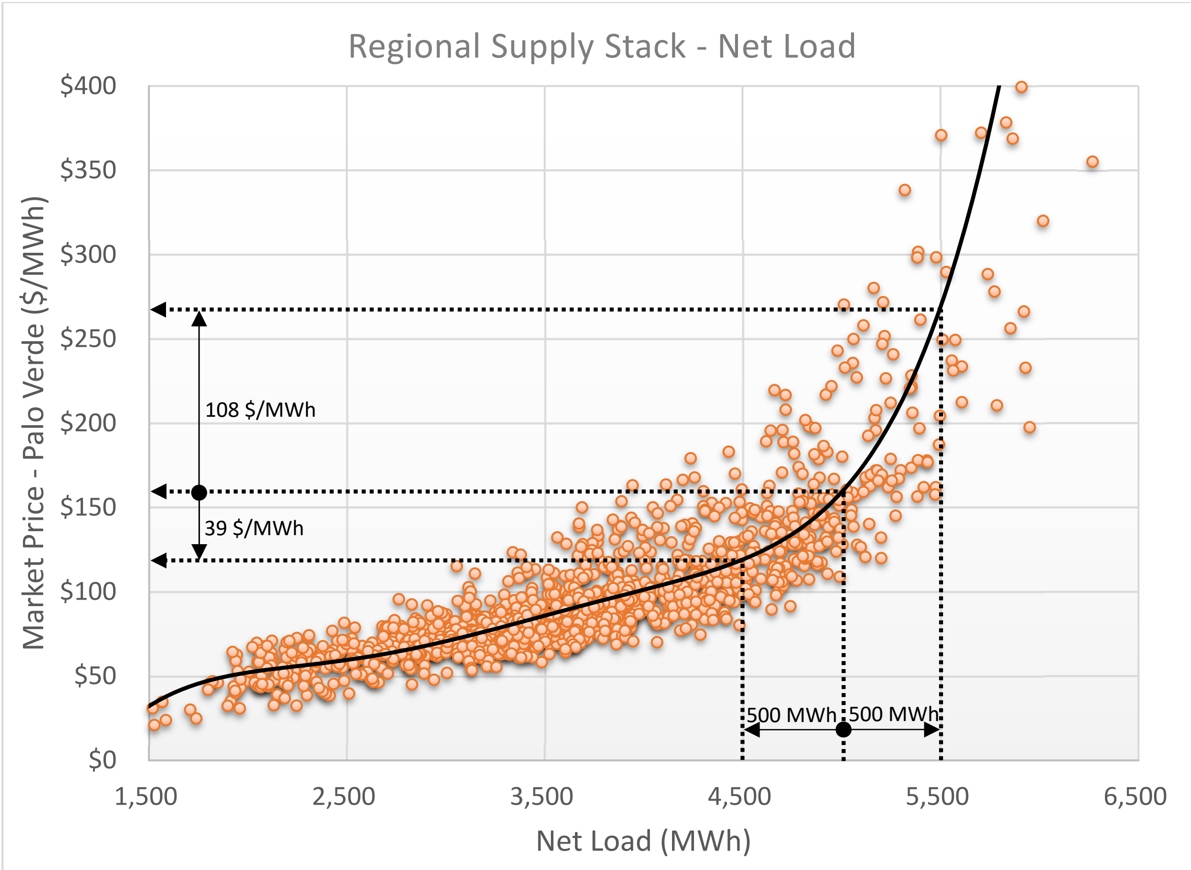
in the regional market prices corresponds to a proportionate and material change in NPC and the associated NPC forecast accuracy (variance).

Q. Is it expected that these errors in the NPC forecast will cancel out over time and produce accuracy in the long run?

A. Unfortunately, not. There is an asymmetry in the response of market prices to changes in regional generation or load. As an illustrative example, Figure 8 below depicts a proxy supply curve (with inelastic demand) based on actual load, wind, and solar data within the region during the summer of 2022, scaled to Rocky Mountain Power load.

In this illustrative example, because of the asymmetry of regional market price response, a 500 MWh *increase* in net load (load less wind less solar) results in a $108/MWh increase in market price whereas an identical 500 MWh *decrease* in net load results in only a $39/MWh decrease to market price.

Figure 8



Q. What are the immediate consequences to NPC of this asymmetry in the response of market prices to changes in regional generation or load?

A. As previously illustrated in Figure 5 above, because NPC move in proportion to regional market prices, and continuing with the illustrative example provided above, we observe that an unexpected increase in net load will increase NPC by an amount far greater than the decrease in NPC observed because of an identical and opposite unexpected decrease in net load.

This asymmetrical response biases the NPC forecast persistently downwards such that any attempt to accurately model, and not over-forecast, will probabilistically result in actual NPC being greater than forecast NPC and consequently, persistent under-recovery of NPC through the sharing band as evidenced in 2021 and 2022.

Q. Apart from persistent under-recovery, what are the long-term implications to NPC of this asymmetry in the response of market prices to changes in regional generation or load?

A. As weather dependent generation continues to proliferate throughout the region as illustrated above in Figure 7, the one to two years out regional generation forecasts and the associated regional market price forecasts will become less accurate. This, in turn, will factually and substantially increase the difficulty of creating accurate NPC forecasts.

Q. Although regional proliferation of weather dependent generation results in less accurate price forecasts and correspondingly less accurate NPC forecasts; does this weather-dependent generation lower the Company's NPC?

A. Yes. Since calendar year 2020 the Company has repowered existing wind facilities,[22] gained ownership of new wind facilities[23] and built new transmission lines,[24] all of which are operational in the test period. Without these new wind resources and the associated transmission lines to move the generation to load, the 2024 NPC forecast would be $343 million higher on a total-Company basis, approximately $47 million on a Wyoming-allocated basis.

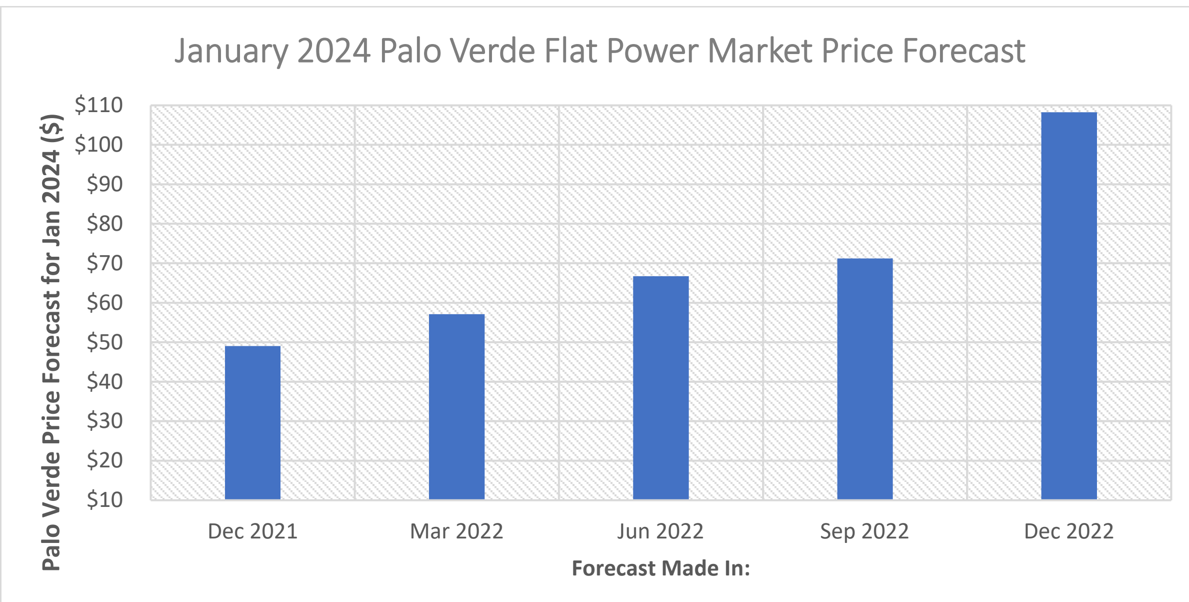
[22] Dunlap, Foote Creek I, Glenrock I, Glenrock III, Goodnoe Hills, High Plains, Leaning Juniper, Marengo I, Marengo II, McFadden Ridge, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II.
[23] Cedar Springs II, Ekola Flats, Foote Creek II, Foote Creek III, Foote Creek IV, Pryor Mountain, Rock Creek 1, Rock River 1, TB Flats I, TB Flats II.
[24] Gateway West Segment D.2, Gateway South.

An Uncertain and Dynamic Future

Q. How has the uncertainty (unreliability) of regional power market price forecasts manifested?

A. Using January 2024 as an example, regional power market price forecasts demonstrate unreliability through an examination of the quarter-over-quarter forecasts of average power market prices at Palo Verde for the month of January 2024. The illustration in Figure 9 below starts with the prices taken from real broker quotes on December 31, 2021 and ends with the quotes taken in December 30, 2022.

Figure 9



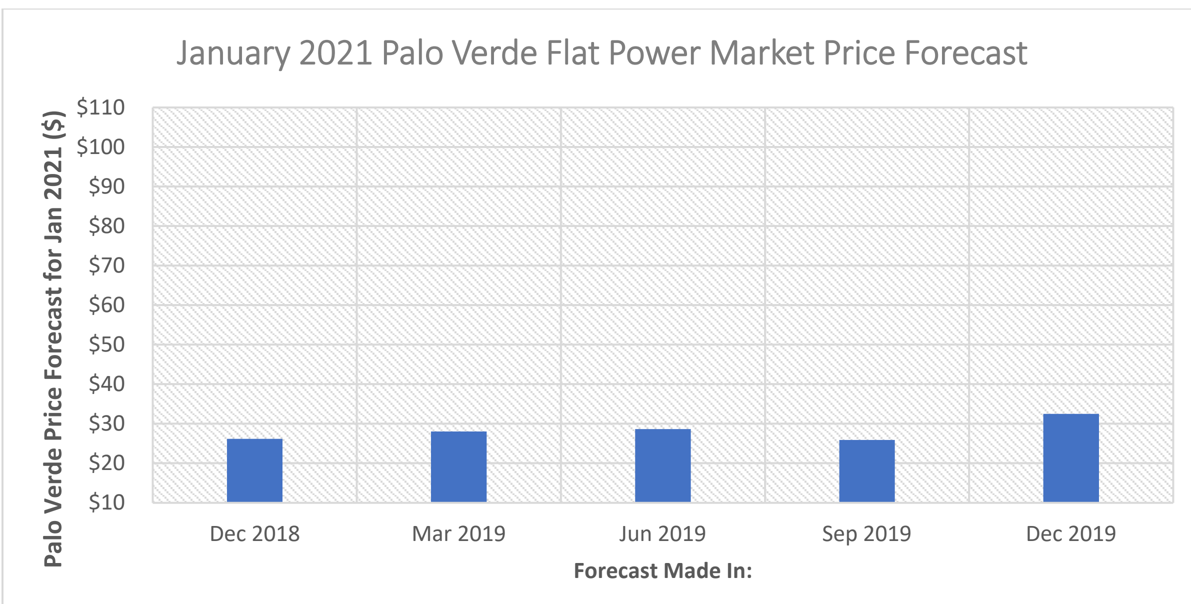
Q. What does Figure 9 show?

A. Figure 9 above makes clear the fact that the price expectations for January 2024 increased every quarter by a substantial amount. Were this NPC forecast created prior to December 31, 2022, the NPC would look markedly different, and substantially lower than the current forecast. This scenario of under-forecast exacerbates as one goes backward in time. It is near impossible to determine with any reasonable degree of accuracy what the January 2024 price will actually be in January of 2024.

Q. How does this price forecast of January 2024 compare to January 2021?

A. Figure 10 below illustrates similar quarter-over-quarter forecasts for the month of January 2021. It starts with the prices taken from real broker quotes on December 31, 2018 and ends with the quotes taken in December 30, 2019. Figure 10 below is scaled identically to Figure 9 above and illustrates that during calendar year 2019, the price expectations for January 2021 were relatively stable. Comparing Figure 10 against Figure 9 demonstrates the factual increase in the unreliability of regional market price forecasts between the 2020 GRC and this filing.

Figure 10



Q. Forward (future) market prices have become near impossible to determine with any reasonable degree of accuracy. How does this impact the NPC forecast?

A. In an identical fashion. The NPC forecast has become near impossible to calculate with any reasonable degree of accuracy, in either direction.

Q. Please elaborate.

A. Regional forward power market prices do not trend upwards indefinitely. The historical data, as illustrated above in Figure 4, shows a recent trend of substantial and unprecedented under-forecast of NPC. However, the opposite trend is probable. At some point, a re-creation of Figure 9 above may show quarter-over-quarter decreases by equally substantial amounts and these decreases will be un-precedentially unfavorable to Wyoming customers under the ECAM sharing band. Essentially, as market prices drop, the higher forecast will result in 20 percent of that benefit being retained by the Company instead of flowing to customers.

Q. What other factors exacerbate the unreliability of future market prices?

A. The conflict in Ukraine has impacted regional forward natural gas market prices and it is uncertain as to how long either the conflict or the repercussions from the conflict will persist. Additionally, there has been an uptick in unpredictable and extreme weather events and market participants hold expectations of a continuation of these unpredictable events which place a premium on regional forward power market prices.

Q. How has the conflict in Ukraine impacted regional natural gas fuel prices?

A. The conflict in Ukraine has decreased European availability of natural gas, previously sourced from Russian imports. With decreased European supply, the associated European demand has turned to U.S. domestic supply to fill the gap and the increased competition over domestic supply has driven regional natural gas fuel prices upwards with increases in domestic production unable to keep pace with the increased demand. This increase in natural gas fuel prices correspondingly increases regional natural gas market prices and regional power market prices, in that order. It is uncertain as to how long, and in what direction, these factors will continue to impact regional prices.

Q. How have extreme weather events impacted regional power market prices?

A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of the Pacific Northwest[25] and the consequent decrease in expected hydroelectric generation diminishes the expected regional energy supply.

Furthermore, calendar years 2020, 2021 and 2022 have seen an increase in abnormal/extreme weather events that have resulted in higher-than-expected load during stressed system conditions, and this trend has set expectations amongst market participants for similar conditions in 2024. Therefore, many utilities across the region have revised their expectations of load profiles upwards, which limits excess supply offered into the regional power markets.

Although market participants hold expectations of a continuation of unpredictable weather events, these events are by definition uncertain and may or may not materialize on time, or at all. Consequently, the actual 2024 power market prices are equally uncertain.

Q. What other uncertain elements in this dynamically evolving industry landscape are of substantial impact to NPC?

A. The expansion and revision of the EPA's Cross-State Air Pollution Rule on NO_x emissions limits (also referred to as the OTR) that was announced in draft rules issued in 2022 is an on-going uncertainty. As discussed in more detail in the testimony of Ms. Steward, based on the EPA's publications to date it is unclear whether or not Wyoming

[25] *U.S. Drought Monitor, supra* note 1.

NO_x emissions will be subject to OTR limits in 2024 and beyond. The Company's current modeling assumption is based on the clear initial guidance from the EPA and Wyoming is assumed subject to OTR NO_x emissions limits in 2024.

Q. What are the implications to NPC?

A. As described in detail further above in my testimony, the inclusion or exclusion of Wyoming within the OTR impacts NPC by $118 million.

Q. What are the ECAM sharing band implications of this NPC impact?

A. Since the Company's current modeling assumption is that Wyoming is subject to the OTR in 2024, if clear guidance is not provided by the EPA (and potentially the courts), Wyoming customers may be subject to an over-collection (i.e., the Company may over-recover NPC). Furthermore, even if the EPA continues with its initial guidance and subjects Wyoming to the OTR in 2024, the decision can be reversed in future years, again exposing Wyoming customers to an over-collection.

Q. Will resolution on the OTR issue resolve the potential harm to Wyoming customers?

A. No. As various federal and state entities continue to advance GHG reduction goals, these types of emission reduction policies will likely become more common, appear at greater frequency and be subject to substantial uncertainty. This uncertainty cuts both ways and can result in substantial over-recovery or under-recovery of NPC. When the Commission rendered its decision in the original ECAM, this dynamic of uncertain and ambitious federal and state environmental compliance requirements had not yet come to pass and the ECAM sharing band was designed under that paradigm.

Now, in this uncertain and dynamic industry landscape, the accuracy of modeling supporting the forecasts is further challenged and Wyoming customers are exposed to rates based on policies which may be both transient in nature and of substantial impact to NPC. This further argues for Wyoming customers to pay 100 percent of prudently incurred actual NPC, no more and no less, by allowing the Company to return to customers NPC that were over-recovered or recover from customers NPC that were under-recovered.

The ECAM Incentives and the Company's Proposal

Q. Under the restrictions of the ECAM sharing band and the current and future state of the western interconnection, what steps can be taken to achieve equitable outcomes for both customers and the Company?

A. The concept of an equitable outcome where the Company has the opportunity to recover all prudently incurred NPC without systemic disadvantage to either customers or the Company could be achieved through any combination of three methods – two of which are in direct contradiction to the as-designed incentives of the ECAM and prudent utility practice: 1) Abstain from joining the EDAM and exit the EIM, thereby regaining some measure of control over the accuracy of NPC modeling and forecasting; 2) Artificially engineer the NPC forecast with an upward bias to account for the expectation of under-recovery; or 3) Eliminate the sharing band.

Although the first two methods listed above may increase the accuracy of the NPC forecast and assist in attaining equitable outcomes, the first would raise actual NPC and the second is the result of an inappropriate ECAM sharing band incentive and is not good utility practice in any forecasting arena. The third step is at the sole discretion of the Commission.

Q. Which incentive is being achieved without the application of the ECAM sharing band?

A. "[T]o encourage the Company to use its best efforts to control costs."[26] Through the upcoming EDAM participation along with the multiple, powerful incentives to keep energy costs low—including electric industry transformation, increased competition, and regulatory disallowances—the Company has employed best efforts to control costs to the point where the economic control of the majority of NPC will no longer be under the purview of the Company, but instead, an independent system operator.

Q. Which ECAM sharing band incentive is no longer achievable under the current and future energy landscape?

A. "[T]o encourage the accuracy of modeling supporting the forecasts."[27] Ongoing and irreversible changes in the resource mix across the western interconnection which result in less accurate regional forward market prices has made it near impossible for the Company to achieve accuracy of modeling to support the forecasts.

Q. Which incentive has always been and will continue to be achieved even if the ECAM sharing band is eliminated?

A. "[T]o avoid creating commercial disadvantage to roughly 70 percent of RMP's load in Wyoming, which would ultimately be detrimental to all Wyoming customers."[28] Wyoming customers will pay 100 percent of prudently incurred actual NPC, lowered

[26] *See,* Docket No. 20000-368-EA-10 (Record No. 12477), Memorandum Opinion, Findings and Order (Feb. 4, 2011).
[27] *Id.*
[28] *Id.*

by EDAM participation, no more and no less. Parties will also be able to effectively review each year's ECAM application to determine if the costs being requested were prudent and in the public interest. The proposed ECAM sharing band elimination will not place Wyoming customers at a disadvantage but will instead allow the Company to return to customers NPC that were over-recovered or recover from customers NPC that were under-recovered.

Q. Which ECAM sharing band incentive appears to be no longer relevant to NPC?

A. "[T]o use the existing forecasting mechanisms."[29] Since the proposed test period matches the rate effective period, the pre-existing forecasting mechanisms that underpinned the design of the ECAM are no longer relevant and as a consequence, it appears that this ECAM incentive is no longer relevant.

Q. Of the four ECAM sharing band incentives, since one is achieved absent the ECAM, one is no longer achievable, one has been and will continue to be achieved, and one appears to be no longer relevant, what is the Company's proposal?

A. The Company proposes to eliminate the ECAM sharing band to allow for 100 percent return or recovery of the mechanism's revenues or costs to or from customers.

Q. Does the elimination of the ECAM sharing band have the potential to benefit customers?

A. Yes. Considering the increasing inaccuracy of regional forward market prices it is conceivable and probable, as previously mentioned, that there will be years in which the NPC forecast is substantially higher than the actual NPC, resulting in an *over-*

[29] *Id.*

recovery of NPC. Under this scenario, all over-recovered costs would flow back to customers and eliminate their exposure to this downside risk.

Q. Does the elimination of the ECAM sharing band imply a prudence review that is monumental in scope?

A. No. With participation in an organized market, the quantity of transactions to review are less numerous because the majority of NPC transactions and decisions will be automated under the purview of an independent system operator. The remaining NPC transactions relevant for prudency reviews become smaller by magnitudes and therefore manageable instead of monumental.

XII. CONCLUSION

Q. Please summarize your direct testimony.

A. The Company's NPC as modeled in the test period in this case have increased by $1.122 billion on a total-Company basis, approximately 78 percent, since the 2020 GRC. This increase is driven by: 1) the bias towards under-recovery that resulted in a NPC forecast in the 2020 GRC that was too low; 2) increases in purchased power and decreases in wholesale sales revenue that offset a reduction in generation due to the OTR, the WA-GHG program, the gas conversion of Jim Bridger units 1 and 2, increased regulation reserve requirements and the expectation of lower hydroelectric generation; and 3) the increase is offset by the Gateway South transmission project.

The upcoming participation in a complete organized market (EDAM) allows for an independent system operator to have economic control over day-ahead, hour-ahead and intra-hour generation commitment/dispatch and market transactions. This in turn allows for the majority of NPC to be as low as modern optimization techniques allow for, while simultaneously removing the ability of the Company to control that same majority.

Furthermore, as wind, solar and other weather dependent resources proliferate across the region, from Canada to Mexico, it is near impossible to accurately forecast NPC a year or more in advance and furthermore, customers bear an increased risk of over-collection as the NPC forecast is exposed to substantial uncertainty resulting from the electric industry being in the midst of permanent and unprecedented change.

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission adopt the proposed base NPC for the test period of $2.553 billion on a total-company basis and $360.3 million on a Wyoming-allocated basis.

I also recommend the Commission approve modifications to the design of the ECAM to remove the sharing band.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM	DOCKET NO. 20000-___-ER-23 (RECORD NO. _____)

AFFIDAVIT, OATH AND VERIFICATION

Ramon Mitchell (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Manager, Net Power Costs for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Manager, Net Power Costs.

Further Affiant Sayeth Not.

Dated this 27 day of February, 2023

Ramon Mitchell
Manager, Net Power Costs

STATE OF Oregon)
) SS:
COUNTY OF Multnomah)

The foregoing was acknowledged before me by Ramon Mitchell on this 27 day of February, 2023. Witness my hand and official seal.

Notary Public

My Commission Expires: 9/6/2025

OFFICIAL STAMP
KELLY ANN WIGGINS
NOTARY PUBLIC - OREGON
COMMISSION NO. 1015825
MY COMMISSION EXPIRES SEPTEMBER 06, 2025

Rocky Mountain Power
Exhibit 10.1
Docket No. 20000-___-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Cost Report

March 2023

WYGRC 2024 NPC Final 02 16 2023

	Total	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
								$					
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hurricane Sale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper Revenue	$ 353,394	$ 26,267	$ 23,495	$ 27,826	$ 16,228	$ 20,336	$ 22,380	$ 55,884	$ 55,044	$ 38,231	$ 24,244	$ 19,233	$ 24,228
PSCo_Sale	$ 11,561,948	$ 654,964	$ 942,025	$ 1,003,664	$ 713,460	$ 576,640	$ 950,064	$ 881,326	$ 2,979,360	$ 846,560	$ 805,283	$ 598,562	$ 610,040
Total Long Term Firm Sales	$ 11,915,342	$ 681,231	$ 965,520	$ 1,031,490	$ 729,688	$ 596,976	$ 972,444	$ 937,210	$ 3,034,404	$ 884,791	$ 829,527	$ 617,795	$ 634,268
Short Term Firm Sales													
Borah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Balancing Sales													
COB	$ 110,330,152	$ 11,669,369	$ 7,628,984	$ 5,604,567	$ 3,644,115	$ 4,236,182	$ 6,314,101	$ 7,685,617	$ 9,284,345	$ 14,777,929	$ 13,049,209	$ 12,420,938	$ 14,014,796
Four Corners	$ 82,006,170	$ 13,240,040	$ 5,896,023	$ 6,282,901	$ 4,318,007	$ 2,600,160	$ 4,164,920	$ 4,824,863	$ 3,520,197	$ 8,557,463	$ 6,996,597	$ 9,475,748	$ 12,129,252
Mead	$ 1,275,851	$ 176,007	$ 45,724	$ (5,377)	$ 186,636	$ 13,487	$ 34,203	$ 126,212	$ 302,992	$ 398,535	$ 162,324	$ 24,513	$ (189,405)
Mid Columbia	$ 214,332,919	$ 29,702,783	$ 16,620,848	$ 12,296,574	$ 9,906,293	$ 7,708,421	$ 4,561,697	$ 27,701,133	$ 31,678,240	$ 22,152,806	$ 17,577,683	$ 14,445,728	$ 19,980,712
Mona	$ 20,734,567	$ 3,048,429	$ 2,954,040	$ 1,191,426	$ 306,928	$ 111,235	$ 1,565,314	$ 834,822	$ 1,532,075	$ 5,190,450	$ 1,258,733	$ 1,017,206	$ 1,723,909
NOB	$ 17,252,126	$ 1,651,150	$ 1,417,774	$ 1,424,472	$ 528,641	$ 402,942	$ 1,239,247	$ 1,838,447	$ 2,673,733	$ 2,403,528	$ 1,401,433	$ 1,373,639	$ 897,121
Palo Verde	$ 5,629,349	$ 699,869	$ 403,159	$ 336,624	$ 80,410	$ 48,862	$ 515,656	$ 551,550	$ 1,289,787	$ 357,751	$ 420,183	$ 477,019	$ 448,481
Trapped Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total System Balancing Sales	$ 451,561,134	$ 60,187,647	$ 34,966,552	$ 27,131,186	$ 18,971,031	$ 15,121,288	$ 18,395,138	$ 43,562,643	$ 50,281,368	$ 53,838,463	$ 40,866,162	$ 39,234,791	$ 49,004,866
Total Special Sales For Resale	$ 463,476,476	$ 60,868,878	$ 35,932,072	$ 28,162,676	$ 19,700,719	$ 15,718,263	$ 19,367,582	$ 44,499,852	$ 53,315,772	$ 54,723,253	$ 41,695,688	$ 39,852,586	$ 49,639,134

Purchased Power & Net Interchange													
Long Term Firm Purchases													
Appaloosa 1A Solar	$ 8,781,386	$ 476,579	$ 523,356	$ 771,696	$ 833,331	$ 975,792	$ 1,030,696	$ 902,929	$ 879,702	$ 829,738	$ 660,259	$ 490,655	$ 406,654
Appaloosa 1B Solar	$ 5,854,258	$ 317,719	$ 348,904	$ 514,464	$ 555,554	$ 650,528	$ 687,130	$ 601,953	$ 586,468	$ 553,159	$ 440,172	$ 327,103	$ 271,103
Castle Solar UoU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar IHC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind	$ 11,764,725	$ 1,348,848	$ 1,136,654	$ 1,032,244	$ 1,016,035	$ 830,825	$ 743,881	$ 742,782	$ 585,990	$ 827,498	$ 1,090,534	$ 1,068,343	$ 1,341,093
Cedar Springs Wind III	$ 8,939,587	$ 1,025,293	$ 863,560	$ 784,236	$ 772,111	$ 631,271	$ 565,347	$ 564,366	$ 445,199	$ 628,829	$ 828,668	$ 811,823	$ 1,018,881
Cedar Springs Wind IV	$ 43,667	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,667
Combine Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cove Mountain Solar	$ 3,824,831	$ 183,114	$ 199,253	$ 335,342	$ 365,062	$ 420,185	$ 451,894	$ 438,350	$ 414,770	$ 355,679	$ 286,322	$ 205,725	$ 169,135
Cove Mountain Solar II	$ 9,457,003	$ 453,001	$ 492,928	$ 829,598	$ 903,121	$ 1,039,489	$ 1,117,932	$ 1,084,426	$ 1,026,092	$ 879,908	$ 708,326	$ 506,098	$ 416,084
Deseret Purchase	$ 27,684,996	$ 3,228,408	$ 3,092,614	$ 3,010,571	$ 2,973,793	$ 3,009,156	$ 2,719,178	$ 3,228,408	$ 3,228,408	$ 3,194,459	$ -	$ -	$ -
Eagle Mountain - UAMPS/UMPA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 20yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 25yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gemstate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Graphite Solar	$ 6,247,480	$ 311,883	$ 365,922	$ 557,963	$ 612,332	$ 686,777	$ 704,723	$ 687,351	$ 642,989	$ 576,256	$ 480,478	$ 355,140	$ 265,665
Hermiston Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Horseshoe Solar	$ 5,332,320	$ 233,718	$ 300,509	$ 437,779	$ 495,804	$ 591,109	$ 654,482	$ 643,280	$ 609,542	$ 507,018	$ 407,367	$ 251,783	$ 199,930
Hunter Solar	$ 7,031,207	$ 369,331	$ 433,652	$ 637,866	$ 665,722	$ 759,120	$ 785,546	$ 746,797	$ 702,015	$ 654,578	$ 558,601	$ 396,190	$ 321,788
Hurricane Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Buythru	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Reserves	$ 3,264,140	$ 272,680	$ 264,660	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680
Milican Solar	$ 2,898,880	$ 95,313	$ 150,647	$ 222,859	$ 280,511	$ 332,937	$ 362,395	$ 408,109	$ 360,617	$ 290,222	$ 190,032	$ 121,715	$ 83,523
Milford Solar	$ 6,937,492	$ 350,630	$ 418,195	$ 595,592	$ 662,485	$ 778,851	$ 821,177	$ 731,293	$ 704,005	$ 656,707	$ 529,625	$ 385,321	$ 303,612
Nucor	$ 7,129,800	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150
Old Mill Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monsanto Reserves	$ 20,600,000	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667
Pavant III Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PGE Cove	$ 140,000	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667
Prineville Solar	$ 1,931,376	$ 65,430	$ 103,415	$ 148,062	$ 186,364	$ 221,194	$ 240,766	$ 271,137	$ 239,584	$ 192,816	$ 126,252	$ 80,864	$ 55,491
Rocket Solar	$ 5,684,265	$ 257,917	$ 322,155	$ 469,128	$ 531,644	$ 621,291	$ 698,208	$ 715,730	$ 647,631	$ 544,498	$ 414,062	$ 252,964	$ 209,039
Sigurd Solar	$ 5,900,441	$ 308,030	$ 356,200	$ 507,232	$ 553,807	$ 636,517	$ 699,580	$ 650,415	$ 596,230	$ 556,646	$ 451,695	$ 317,435	$ 266,651
Skysol Solar	$ 5,920,135	$ 277,872	$ 373,145	$ 543,974	$ 572,773	$ 517,340	$ 856,561	$ 578,605	$ 797,081	$ 416,253	$ 495,730	$ 251,550	$ 239,252
Small Purchases east	$ 14,288	$ 1,173	$ 1,213	$ 1,172	$ 1,172	$ 1,233	$ 1,203	$ 1,226	$ 1,202	$ 1,153	$ 1,157	$ 1,209	$ 1,176
Small Purchases west	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Soda Lake Geothermal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Buttes Wind	$ 20,858,257	$ 2,812,455	$ 1,934,623	$ 2,152,484	$ 1,628,729	$ 1,438,793	$ 1,215,151	$ 811,932	$ 957,067	$ 1,194,423	$ 1,748,905	$ 2,371,134	$ 2,592,560
Top of the World Wind	$ 38,689,566	$ 3,276,985	$ 3,065,567	$ 3,276,985	$ 3,171,276	$ 3,276,985	$ 3,171,276	$ 3,276,985	$ 3,276,985	$ 3,171,276	$ 3,276,985	$ 3,171,276	$ 3,276,985
Wolverine Creek Wind	$ 10,735,370	$ 793,717	$ 942,652	$ 1,181,937	$ 1,087,538	$ 821,216	$ 882,210	$ 698,831	$ 664,714	$ 785,048	$ 864,179	$ 1,004,655	$ 1,008,672
Glen Canyon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rush Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anticline Wind	$ 18,647	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,647
Boswell Springs Wind	$ 57,102	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 57,102
Two River Wind LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Creek	$ 9,824,810	$ -	$ -	$ -	$ -	$ -	$ 19,719	$ 1,377,208	$ 1,089,634	$ 1,309,941	$ 2,181,521	$ 2,132,507	$ 1,714,280
UT Schedule Adjustment	$ (33,198,571)	$ (1,463,536)	$ (1,769,202)	$ (2,996,795)	$ (3,347,722)	$ (3,977,703)	$ (4,018,922)	$ (3,768,575)	$ (3,525,330)	$ (3,024,858)	$ (2,525,108)	$ (1,597,900)	$ (1,182,918)
Long Term Firm Purchases Total	$ 202,367,458	$ 17,319,045	$ 16,243,105	$ 17,609,552	$ 17,116,603	$ 16,858,070	$ 17,005,296	$ 17,988,702	$ 17,525,760	$ 17,696,411	$ 15,810,926	$ 15,500,754	$ 15,693,233

Qualifying Facilities													
QF California	$ 1,658,369	$ 141,267	$ 141,402	$ 153,489	$ 154,589	$ 135,224	$ 131,654	$ 132,928	$ 131,618	$ 127,262	$ 132,956	$ 139,460	$ 136,519
QF Idaho	$ 7,034,517	$ 579,055	$ 521,178	$ 596,029	$ 634,937	$ 720,838	$ 711,597	$ 626,253	$ 528,432	$ 493,745	$ 554,618	$ 531,787	$ 536,048
QF Oregon	$ 38,355,763	$ 1,921,262	$ 2,312,674	$ 3,119,183	$ 4,024,168	$ 4,270,174	$ 4,352,342	$ 4,565,124	$ 4,102,556	$ 3,413,575	$ 2,651,709	$ 1,946,296	$ 1,676,698
QF Utah	$ 6,814,556	$ 400,464	$ 458,756	$ 537,735	$ 647,822	$ 710,670	$ 730,764	$ 663,990	$ 669,527	$ 658,260	$ 568,747	$ 428,130	$ 339,690
QF Washington	$ 595,442	$ 5,111	$ 10,028	$ 16,495	$ 31,298	$ 61,974	$ 118,753	$ 133,374	$ 117,176	$ 75,316	$ 15,663	$ 5,880	$ 4,373
QF Wyoming	$ 78,034	$ 9,487	$ 7,388	$ 9,072	$ 7,728	$ 7,134	$ 2,863	$ 4,347	$ 4,859	$ 6,608	$ 6,298	$ 7,080	$ 5,169
Biomass One QF	$ 18,597,518	$ 1,467,149	$ 1,682,299	$ 1,801,148	$ 1,760,367	$ 1,478,176	$ 1,902,739	$ 1,373,031	$ 1,795,085	$ 1,379,180	$ 1,774,602	$ 1,408,658	$ 775,084
Chopin Wind QF	$ 2,048,377	$ 193,044	$ 212,355	$ 168,226	$ 188,753	$ 161,939	$ 177,933	$ 160,795	$ 152,387	$ 133,330	$ 156,651	$ 177,435	$ 165,528
DCFP QF	$ 147,652	$ 5,078	$ 1,899	$ 1,965	$ 2,612	$ 5,237	$ 8,926	$ 19,768	$ 53,161	$ 20,220	$ 14,726	$ 8,333	$ 5,725
Enterprise Solar I QF	$ 12,428,315	$ 605,776	$ 772,740	$ 956,940	$ 1,100,161	$ 1,246,936	$ 1,367,030	$ 1,552,309	$ 1,503,979	$ 1,161,053	$ 940,221	$ 689,473	$ 531,699
Escalante Solar I QF	$ 11,464,945	$ 555,383	$ 702,390	$ 861,800	$ 1,001,202	$ 1,180,119	$ 1,278,616	$ 1,437,770	$ 1,392,853	$ 1,073,040	$ 857,708	$ 627,972	$ 496,091
Escalante Solar II QF	$ 10,801,514	$ 522,020	$ 659,365	$ 811,762	$ 941,605	$ 1,115,246	$ 1,221,823	$ 1,358,137	$ 1,305,905	$ 1,011,320	$ 804,026	$ 587,622	$ 462,683
Escalante Solar III QF	$ 9,936,063	$ 507,994	$ 644,271	$ 787,602	$ 915,846	$ 1,085,562	$ 731,324	$ 1,315,175	$ 1,267,280	$ 982,800	$ 735,783	$ 538,302	$ 424,125
ExxonMobil QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Five Pine Wind QF	$ 9,710,176	$ 563,431	$ 1,038,012	$ 944,560	$ 1,014,433	$ 442,482	$ 736,691	$ 615,701	$ 733,643	$ 820,900	$ 889,560	$ 933,939	$ 976,823
Granite Mountain East Solar QF	$ 10,778,945	$ 538,975	$ 634,052	$ 873,532	$ 974,584	$ 1,145,735	$ 1,244,331	$ 1,333,659	$ 1,255,131	$ 959,245	$ 795,497	$ 568,358	$ 455,845
Granite Mountain West Solar QF	$ 7,121,644	$ 356,801	$ 420,253	$ 579,379	$ 646,457	$ 758,828	$ 823,479	$ 883,781	$ 831,879	$ 634,512	$ 509,122	$ 375,534	$ 301,619
Iron Springs Solar QF	$ 11,073,378	$ 623,133	$ 681,626	$ 875,888	$ 1,002,096	$ 1,119,438	$ 1,269,977	$ 1,344,268	$ 1,314,577	$ 987,521	$ 802,236	$ 566,110	$ 486,508
Latigo Wind Park QF	$ 9,793,430	$ 1,008,523	$ 974,723	$ 1,127,257	$ 888,162	$ 870,272	$ 743,515	$ 687,491	$ 567,983	$ 624,430	$ 806,218	$ 703,907	$ 790,950
Mountain Wind 1 QF	$ 9,042,366	$ 1,421,577	$ 1,090,928	$ 884,151	$ 699,375	$ 494,107	$ 509,817	$ 413,520	$ 443,831	$ 466,242	$ 672,794	$ 930,752	$ 1,015,271
Mountain Wind 2 QF	$ 14,002,090	$ 2,060,743	$ 1,624,957	$ 1,360,834	$ 1,082,104	$ 769,391	$ 912,714	$ 759,165	$ 732,764	$ 769,110	$ 1,005,488	$ 1,432,507	$ 1,492,316
North Point Wind QF	$ 20,647,148	$ 1,124,011	$ 2,125,702	$ 1,999,790	$ 2,164,701	$ 938,564	$ 1,585,605	$ 1,359,834	$ 1,726,325	$ 1,853,270	$ 1,964,389	$ 1,885,477	$ 1,919,480
Oregon Wind Farm QF	$ 14,121,537	$ 1,003,550	$ 1,532,569	$ 1,246,680	$ 1,005,615	$ 725,755	$ 954,399	$ 1,241,939	$ 2,818,117	$ 871,584	$ 870,570	$ 715,262	$ 1,135,497
Orchard Wind 1 QF	$ 1,139,692	$ 63,171	$ 72,099	$ 97,721	$ 124,816	$ 110,803	$ 123,524	$ 123,449	$ 105,362	$ 79,489	$ 84,148	$ 75,107	$ 80,003
Orchard Wind 2 QF	$ 1,139,025	$ 61,356	$ 70,438	$ 91,023	$ 124,993	$ 112,506	$ 123,255	$ 125,420	$ 106,117	$ 79,928	$ 85,657	$ 76,765	$ 81,568
Orchard Wind 3 QF	$ 1,139,264	$ 63,522	$ 68,915	$ 105,763	$ 122,943	$ 112,010	$ 124,350	$ 121,662	$ 105,662	$ 78,908	$ 84,637	$ 72,465	$ 78,427
Orchard Wind 4 QF	$ 1,139,453	$ 63,331	$ 71,377	$ 103,949	$ 122,994	$ 111,676	$ 123,692	$ 122,969	$ 105,683	$ 78,915	$ 82,859	$ 73,472	$ 78,535
Pavant II Solar QF	$ 5,116,247	$ 208,969	$ 282,470	$ 407,283	$ 478,347	$ 499,355	$ 597,409	$ 546,878	$ 758,285	$ 464,865	$ 411,225	$ 254,555	$ 206,606
Pioneer Wind Park I QF	$ 10,709,139	$ 1,308,719	$ 979,538	$ 1,188,677	$ 905,868	$ 709,742	$ 649,747	$ 657,551	$ 685,231	$ 449,790	$ 819,706	$ 1,261,619	$ 1,092,950
Power County North Wind QF	$ 6,161,396	$ 445,195	$ 643,434	$ 644,236	$ 645,185	$ 315,946	$ 462,404	$ 349,087	$ 435,452	$ 404,038	$ 598,734	$ 548,859	$ 668,826
Power County South Wind QF	$ 5,500,991	$ 394,670	$ 567,630	$ 581,722	$ 598,265	$ 271,124	$ 409,979	$ 308,756	$ 406,414	$ 359,373	$ 525,200	$ 496,807	$ 581,053
Roseburg Dillard QF	$ 1,605,357	$ 64,337	$ 238,412	$ 149,346	$ 176,614	$ 110,536	$ 109,492	$ 182,380	$ 248,535	$ 60,050	$ 116,684	$ 74,410	$ 74,560
Sage I Solar QF	$ 2,224,606	$ 79,115	$ 80,953	$ 185,750	$ 201,479	$ 230,722	$ 255,841	$ 330,468	$ 328,474	$ 202,900	$ 152,736	$ 102,564	$ 73,604
Sage II Solar QF	$ 2,226,990	$ 79,198	$ 81,049	$ 185,945	$ 201,695	$ 230,934	$ 256,127	$ 330,821	$ 328,839	$ 203,129	$ 152,889	$ 102,691	$ 73,674
Sage III Solar QF	$ 1,832,725	$ 66,690	$ 67,449	$ 153,415	$ 164,218	$ 189,113	$ 209,266	$ 269,677	$ 267,843	$ 167,470	$ 128,126	$ 86,929	$ 62,528
Spanish Fork Wind 2 QF	$ 2,929,265	$ 196,128	$ 217,811	$ 233,814	$ 182,707	$ 141,420	$ 288,685	$ 247,949	$ 427,513	$ 236,345	$ 290,348	$ 233,897	$ 232,649
Sunnyside QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sweetwater Solar QF	$ 7,625,670	$ 253,990	$ 379,040	$ 551,639	$ 673,027	$ 797,595	$ 957,706	$ 1,095,186	$ 1,019,583	$ 792,992	$ 615,295	$ 292,965	$ 196,650
Tesoro QF	$ 420,138	$ 33,480	$ 70,038	$ 56,601	$ 34,143	$ 10,708	$ 9,267	$ 8,273	$ 59,913	$ 9,285	$ 11,582	$ 24,123	$ 92,725
Three Peaks Solar QF	$ 8,474,921	$ 409,850	$ 492,863	$ 614,683	$ 835,185	$ 866,466	$ 913,479	$ 1,061,665	$ 1,017,830	$ 791,169	$ 669,197	$ 437,902	$ 364,633
Threemile Canyon Wind QF	$ 1,794,101	$ 82,972	$ 172,317	$ 139,659	$ 183,820	$ 181,293	$ 218,186	$ 208,329	$ 181,311	$ 120,822	$ 125,922	$ 99,256	$ 80,214
Utah Pavant Solar QF	$ 6,844,979	$ 259,763	$ 352,596	$ 546,244	$ 642,550	$ 673,453	$ 865,705	$ 762,807	$ 956,395	$ 617,319	$ 578,864	$ 318,588	$ 270,697
Utah Red Hills Solar QF	$ 11,458,023	$ 480,440	$ 640,061	$ 773,732	$ 1,020,201	$ 1,193,809	$ 1,227,730	$ 1,524,395	$ 1,463,201	$ 1,300,074	$ 800,670	$ 579,337	$ 454,373
Qualifying Facilities Total	$ 305,733,761	$ 20,228,726	$ 23,798,056	$ 26,524,722	$ 28,327,666	$ 26,313,015	$ 29,442,736	$ 30,360,081	$ 32,456,710	$ 25,019,385	$ 23,864,061	$ 20,420,587	$ 18,978,017
Mid-Columbia Contracts													
Douglas - Wells	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grant Reasonable	$ (9,177,438)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)
Grant Meaningful Priority	$ 63,502,271	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856
Grant Surplus	$ 2,448,617	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051
Mid-Columbia Contracts Total	$ 56,773,451	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121
Total Long Term Firm Purchases	$ 564,874,669	$ 42,278,892	$ 44,772,282	$ 48,865,396	$ 50,175,390	$ 47,902,206	$ 51,179,153	$ 53,079,904	$ 54,713,590	$ 47,446,917	$ 44,406,109	$ 40,652,462	$ 39,402,371

Storage & Exchange													
Rush lake_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Umpqua Storage Placeholder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cowlitz Swift	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EWEB FC I	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCo Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCO FC III	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SCL State Line	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage & Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Short Term Firm Purchases													
COB	$ 20,243,300	$ 2,925,000	$ 2,812,500	$ 2,925,000	$ -	$ -	$ -	$ 3,910,400	$ 4,060,800	$ 3,609,600	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ 5,719,560	$ 1,931,280	$ 1,857,000	$ 1,931,280	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Purchases	$ 25,962,860	$ 4,856,280	$ 4,669,500	$ 4,856,280	$ -	$ -	$ -	$ 3,910,400	$ 4,060,800	$ 3,609,600	$ -	$ -	$ -
System Balancing Purchases													
COB	$ 63,816,963	$ 3,566,965	$ 7,525,501	$ 7,936,306	$ 885,594	$ 2,122,367	$ 3,901,265	$ 14,068,052	$ 11,489,112	$ 5,228,835	$ 2,830,827	$ 1,807,321	$ 2,454,817
Four Corners	$ 60,253,266	$ 5,404,130	$ 3,602,765	$ 3,088,292	$ 2,581,947	$ 2,654,265	$ 3,707,847	$ 11,287,619	$ 5,984,880	$ 8,439,081	$ 4,830,406	$ 3,959,556	$ 4,712,476
Mead	$ 2,675,683	$ 50,829	$ -	$ 77,256	$ 89,419	$ -	$ 358,092	$ 30,527	$ 655,905	$ 386,271	$ 13,532	$ 83,081	$ 930,772
Mid Columbia	$ 651,623,834	$ 64,621,155	$ 35,703,550	$ 35,141,288	$ 33,123,154	$ 42,425,874	$ 43,422,114	$ 101,891,771	$ 105,815,606	$ 56,774,090	$ 37,594,584	$ 32,008,549	$ 63,102,099
Mona	$ 18,784,350	$ 1,530,580	$ 2,409,532	$ 957,939	$ 326,642	$ 226,888	$ 2,066,422	$ 346,101	$ 1,331,772	$ 4,539,593	$ 1,587,390	$ 1,340,719	$ 2,120,772
NOB	$ 135,998,156	$ 13,725,805	$ 12,043,617	$ 9,517,948	$ 2,109,423	$ 8,157,467	$ 7,392,059	$ 18,795,742	$ 17,805,917	$ 14,889,231	$ 8,492,194	$ 9,980,135	$ 13,088,616
Palo Verde	$ 20,741,224	$ 2,638,333	$ 1,223,845	$ 1,675,831	$ 685,888	$ 1,306,920	$ 1,528,738	$ 2,715,350	$ 3,428,707	$ 103,532	$ 1,944,460	$ 1,758,899	$ 1,730,721
EIM Imports/Exports	$ (132,040,852)	$ (14,965,950)	$ (11,323,929)	$ (9,984,684)	$ (7,446,441)	$ (7,771,253)	$ (8,104,493)	$ (14,645,162)	$ (15,240,008)	$ (12,752,502)	$ (8,710,848)	$ (9,237,720)	$ (11,857,863)
Emergency Purchases	$ 2,328,540	$ -	$ -	$ 20,259	$ -	$ 628,516	$ 43,771	$ 1,160,138	$ 294,275	$ 623	$ 180,959	$ -	$ -
Total System Balancing Purchases	$ 824,181,164	$ 76,571,847	$ 51,184,883	$ 48,430,435	$ 32,355,627	$ 49,751,043	$ 54,315,816	$ 135,650,138	$ 131,566,165	$ 77,608,754	$ 48,763,504	$ 41,700,542	$ 76,282,409
Total Purchased Power & Net Interchange	$ 1,415,018,693	$ 123,707,019	$ 100,626,664	$ 102,152,110	$ 82,531,017	$ 97,653,249	$ 105,494,969	$ 192,640,442	$ 190,340,555	$ 128,665,270	$ 93,169,612	$ 82,353,003	$ 115,684,780
Wheeling & U. of F. Expense													
Firm Wheeling	$ 164,752,159	$ 12,490,080	$ 13,040,611	$ 13,824,578	$ 14,024,746	$ 13,306,106	$ 14,166,003	$ 16,860,947	$ 15,144,770	$ 14,672,784	$ 12,690,570	$ 11,529,224	$ 13,001,740
C&T EIM Admin fee	$ 2,734,506	$ 210,477	$ 192,813	$ 230,652	$ 220,405	$ 231,652	$ 233,135	$ 235,464	$ 256,292	$ 228,219	$ 226,374	$ 224,006	$ 245,016
ST Firm & Non-Firm	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Wheeling & U. of F. Expense	$ 167,486,665	$ 12,700,557	$ 13,233,424	$ 14,055,229	$ 14,245,151	$ 13,537,757	$ 14,399,139	$ 17,096,411	$ 15,401,062	$ 14,901,003	$ 12,916,944	$ 11,753,230	$ 13,246,757
Coal Fuel Burn Expense													
Colstrip	$ 20,264,861	$ 1,347,945	$ 1,697,135	$ 1,793,151	$ 1,644,230	$ 1,613,950	$ 1,515,964	$ 1,987,544	$ 1,970,031	$ 2,015,481	$ 1,413,006	$ 1,668,752	$ 1,597,673
Craig	$ 17,837,976	$ 1,790,948	$ 1,409,758	$ 1,349,401	$ 1,047,333	$ 1,243,692	$ 1,372,831	$ 1,842,889	$ 1,869,966	$ 1,437,347	$ 1,430,757	$ 1,435,560	$ 1,607,495
Dave Johnston	$ 51,244,943	$ 4,887,919	$ 5,149,814	$ 4,331,143	$ 5,101,950	$ 2,535,269	$ 2,804,175	$ 3,745,072	$ 3,838,019	$ 2,868,401	$ 5,162,829	$ 4,943,372	$ 5,876,980
Hayden	$ 11,433,001	$ 986,310	$ 1,016,996	$ 993,917	$ 1,033,257	$ 907,963	$ 960,733	$ 1,037,455	$ 1,062,729	$ 635,520	$ 523,846	$ 1,216,527	$ 1,057,749
Hunter	$ 205,452,234	$ 24,701,039	$ 19,937,398	$ 11,377,114	$ 7,491,217	$ 13,216,516	$ 15,311,138	$ 25,046,932	$ 23,371,698	$ 19,296,441	$ 14,245,434	$ 14,103,820	$ 17,353,488
Huntington	$ 115,234,611	$ 10,534,125	$ 8,851,795	$ 10,404,104	$ 6,104,493	$ 9,844,076	$ 11,065,807	$ 10,678,231	$ 11,315,671	$ 10,703,003	$ 7,559,331	$ 8,167,763	$ 10,006,213
Jim Bridger	$ 161,976,126	$ 15,529,346	$ 14,634,099	$ 15,160,417	$ 12,855,619	$ 8,407,473	$ 10,822,988	$ 15,223,552	$ 13,721,322	$ 11,238,404	$ 15,495,550	$ 15,010,914	$ 13,876,442
Naughton	$ 31,344,672	$ 3,473,542	$ 2,949,573	$ 2,749,834	$ 1,727,132	$ 2,050,481	$ 2,408,181	$ 3,077,597	$ 3,199,590	$ 2,492,329	$ 2,589,035	$ 2,135,805	$ 2,491,574
Wyodak	$ 17,525,266	$ 2,173,199	$ 1,900,766	$ 1,512,471	$ 2,007,234	$ 629,538	$ 754,263	$ 1,247,590	$ 1,203,737	$ 936,121	$ 1,440,232	$ 1,559,442	$ 2,160,673
Total Coal Fuel Burn Expense	$ 632,313,691	$ 65,424,372	$ 57,547,335	$ 49,671,554	$ 39,012,464	$ 40,448,958	$ 47,016,079	$ 63,886,860	$ 61,552,764	$ 51,623,048	$ 49,860,018	$ 50,241,953	$ 56,028,286

Gas Fuel Burn Expense													
Chehalis	$ 191,905,791	$ 27,003,047	$ 19,591,076	$ 16,257,474	$ 12,965,469	$ 13,288,768	$ 6,471,665	$ 16,284,527	$ 16,040,043	$ 13,484,950	$ 13,330,901	$ 16,988,817	$ 20,199,052
Currant Creek	$ 102,897,129	$ 15,528,877	$ 13,904,821	$ 9,917,095	$ 7,479,578	$ 5,400,914	$ 3,791,561	$ 9,006,791	$ 7,625,725	$ 8,838,788	$ 2,030,679	$ 8,388,957	$ 10,983,343
Gadsby	$ 33,106,016	$ 4,732,894	$ 4,459,481	$ 3,638,965	$ 2,472,528	$ 1,509,931	$ 1,140,546	$ 2,855,671	$ 2,122,267	$ 547,757	$ 2,843,673	$ 3,144,888	$ 3,637,413
Gadsby CT	$ 9,266,469	$ 1,741,978	$ 1,618,413	$ 1,291,334	$ 758,595	$ -	$ -	$ 952,246	$ 172,873	$ -	$ 715,033	$ 857,443	$ 1,158,553
Hermiston	$ 46,186,811	$ 6,560,826	$ 5,644,581	$ 2,740,578	$ 3,103,943	$ 1,476,256	$ 2,065,896	$ 2,680,773	$ 4,155,463	$ 3,990,167	$ 4,163,802	$ 5,039,592	$ 4,564,933
Jim Bridger	$ 113,902,913	$ -	$ -	$ -	$ -	$ 5,715,430	$ 12,914,667	$ 15,915,097	$ 16,904,596	$ 13,887,961	$ 14,967,374	$ 15,896,821	$ 17,700,967
Lake Side 1	$ 113,441,706	$ 14,704,128	$ 14,400,482	$ 9,295,389	$ 6,944,720	$ 6,090,882	$ 5,864,622	$ 9,206,627	$ 9,203,045	$ 8,153,337	$ 6,335,461	$ 10,619,152	$ 12,623,860
Lake Side 2	$ 121,425,420	$ 17,506,610	$ 15,593,418	$ 11,740,136	$ 3,274,778	$ 1,106,949	$ 7,035,107	$ 10,933,542	$ 10,969,780	$ 9,456,734	$ 9,069,291	$ 11,093,285	$ 13,645,791
Naughton - Gas	$ 44,979,188	$ 4,528,002	$ 4,101,768	$ 4,544,600	$ 3,332,545	$ 5,479,329	$ 5,714,492	$ 3,787,507	$ 4,748,097	$ 4,166,717	$ 1,963,724	$ -	$ 2,612,407
Total Gas Fuel Burn	$ 777,111,444	$ 92,306,362	$ 79,314,040	$ 59,425,572	$ 40,332,156	$ 40,068,460	$ 44,998,556	$ 71,622,782	$ 71,941,891	$ 62,526,411	$ 55,419,939	$ 72,028,956	$ 87,126,319
Gas Physical	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas Swaps	$ (19,945,513)	$ (10,260,271)	$ (8,075,297)	$ (510,368)	$ 778,905	$ 1,007,515	$ 788,955	$ (1,206,784)	$ (1,390,280)	$ (810,105)	$ 1,736,899	$ 630,930	$ (2,635,612)
Clay Basin Gas Storage	$ (1,988,037)	$ (733,232)	$ (647,448)	$ (211,830)	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ (262,779)	$ (498,446)
Pipeline Reservation Fees	$ 42,641,816	$ 3,595,182	$ 3,528,864	$ 3,593,440	$ 3,560,992	$ 3,535,121	$ 3,468,895	$ 3,592,882	$ 3,600,562	$ 3,411,380	$ 3,593,706	$ 3,563,602	$ 3,597,189
Total Gas Fuel Burn Expense	$ 797,819,710	$ 84,908,041	$ 74,120,160	$ 62,296,813	$ 44,724,296	$ 44,663,338	$ 49,308,648	$ 74,061,124	$ 74,204,415	$ 65,179,928	$ 60,802,786	$ 75,960,710	$ 87,589,450
Other Generation													
Blundell	$ 3,006,964	$ 295,565	$ 157,647	$ 68,204	$ 271,606	$ 148,379	$ 276,832	$ 299,854	$ 312,101	$ 299,309	$ 283,066	$ 288,962	$ 305,438
Blundell Bottoming Cycle	$ 1,316,426	$ 147,826	$ 71,288	$ 19,873	$ 143,083	$ 59,936	$ 114,467	$ 118,207	$ 118,209	$ 114,433	$ 118,260	$ 143,010	$ 147,834
Cedar Springs Wind II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dunlap I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ekola Flats Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek III Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek IV Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glenrock Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glenrock III Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Goodnoe Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
High Plains Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marengo I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marengo II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
McFadden Ridge Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pryor Mountain Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rolling Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Seven Mile Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Seven Mile II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Black Cap Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TB Flats Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TB Flats Wind II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock River 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Integration Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Generation	$ 4,323,390	$ 443,392	$ 228,935	$ 88,076	$ 414,690	$ 208,315	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Net Power Cost	**$ 2,553,485,673**	**$ 226,314,504**	**$ 209,824,448**	**$ 200,101,107**	**$ 161,226,899**	**$ 180,793,354**	**$ 197,242,552**	**$ 303,603,045**	**$ 288,613,334**	**$ 206,059,739**	**$ 175,454,998**	**$ 180,888,283**	**$ 223,363,411**

Rocky Mountain Power
Exhibit 10.2
Docket No. 20000-___-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE
COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Cost Aurora Test Report

March 2023

Net Power Cost Report

-- 12 months ended December 2021

Aurora Test NPC Report

	Total	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	11/1/2021	12/1/2021
							$						
Special Sales For Resale													
Long Term Firm Sales													
Black Hills Losses_S	**308,860**	26,315	21,811	23,518	22,569	21,526	33,190	28,307	25,794	26,552	26,173	25,272	27,832
Black Hills Sale-MC_S	**3,714,881**	352,854	345,348	381,005	260,897	132,813	168,939	358,954	334,088	341,594	352,854	331,273	354,262
Black Hills Sale-UTS_S	**2,095,040**	178,500	147,946	159,524	153,092	146,016	225,135	192,008	174,962	180,108	177,535	171,424	188,792
Black Hills Sale-WYE_S	**1,789,443**	152,463	126,365	136,255	130,761	124,717	192,295	164,000	149,441	153,836	151,638	146,419	161,253
Leaning Juniper Revenue_S	**105,254**	7,601	7,384	9,260	5,355	4,684	6,043	14,266	16,102	10,939	7,961	6,724	8,936
Hurricane Sale_S	**7,474**	623	623	623	623	623	623	623	623	623	623	623	623
Total Long Term Firm Sales	**8,020,951**	**718,356**	**649,476**	**710,184**	**573,296**	**430,379**	**626,225**	**758,158**	**701,009**	**713,652**	**716,784**	**681,735**	**741,698**
Short Term Firm Sales													
STF Borah_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF COB_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Colorado_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Four Corners_S	**21,354,660**	3,522,890	2,974,080	3,095,370	1,977,600	1,958,400	1,977,600	0	0	0	1,971,460	1,905,800	1,971,460
STF Mead_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mid Columbia_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mona_S	**7,750,000**	1,277,800	1,202,400	1,345,800	338,000	325,000	338,000	0	0	0	985,000	953,000	985,000
STF Palo Verde_S	**23,424,050**	3,801,450	3,397,800	3,751,050	1,877,100	1,834,950	1,877,100	0	0	0	2,320,550	2,243,500	2,320,550
STF PP-GC_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming East_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming North_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Short Term Firm Sales	**52,528,710**	**8,602,140**	**7,574,280**	**8,192,220**	**4,192,700**	**4,118,350**	**4,192,700**	**0**	**0**	**0**	**5,277,010**	**5,102,300**	**5,277,010**
System Balancing Sales													
COB-Sale	**30,427,339**	3,321,041	2,293,355	2,180,958	1,039,510	1,269,402	1,794,325	2,202,105	2,341,634	2,079,633	3,621,494	3,901,647	4,382,234
Four Corners-Sale	**42,302,885**	3,616,086	2,682,091	1,824,757	2,167,706	1,285,084	2,332,335	6,126,247	5,688,306	5,761,445	3,516,089	3,408,296	3,894,444
Mead-Sale	**27,629,244**	3,348,249	2,397,171	1,442,945	926,949	1,123,344	1,722,920	2,366,515	3,561,802	3,095,697	2,591,993	2,557,454	2,494,205
Mid Columbia-Sale	**34,612,093**	4,897,083	2,708,596	981,339	1,039,686	551,854	1,601,827	4,489,554	5,590,328	4,654,937	3,100,223	2,428,095	2,568,571
Mona-Sale	**21,211,278**	2,080,627	1,218,820	160,368	985,792	1,033,466	1,965,544	2,312,725	2,418,449	5,456,820	1,344,863	1,112,031	1,121,774
NOB-Sale	**5,309,085**	0	0	71,541	695,008	217,231	90,618	1,093,834	1,576,831	627,172	40,264	76,189	820,397
Palo Verde-Sale	**28,708,926**	(155,506)	(133,364)	(146,895)	850,630	979,874	1,252,619	8,421,419	9,324,164	6,125,457	683,077	695,432	812,019
Trapped Energy Sale	**101,435**	0	0	93,029	0	500	0	0	0	0	0	7,906	0
Total System Balancing Sales	**190,302,286**	**17,107,580**	**11,166,669**	**6,608,042**	**7,705,281**	**6,460,755**	**10,760,187**	**27,012,400**	**30,501,514**	**27,801,162**	**14,898,003**	**14,187,049**	**16,093,644**
Total Special Sales For Resale	**250,851,948**	**26,428,076**	**19,390,425**	**15,510,447**	**12,471,277**	**11,009,484**	**15,579,112**	**27,770,557**	**31,202,522**	**28,514,815**	**20,891,797**	**19,971,084**	**22,112,352**

Purchased Power & Net Interchange													
Long Term Firm Solar Purchases													
SR_Cove Mountain_P	**3,863,928**	185,318	194,698	339,380	369,457	425,244	457,334	443,628	419,764	359,961	289,769	208,202	171,172
SR_Cove Mountain II_P	**343,571**	28,534	28,675	28,713	28,701	28,534	28,701	28,624	28,624	28,609	28,624	28,609	28,624
SR_Hunter_P	**7,122,377**	374,917	425,032	647,514	675,791	770,602	797,428	758,093	712,634	664,479	567,050	402,182	326,655
SR_Milford_P	**7,081,167**	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,079	671,702	541,718	394,119	310,565
SR_Milican_P	**2,668,657**	90,574	138,221	204,961	257,983	306,198	333,291	375,334	331,655	266,914	174,771	111,940	76,815
SR_Old Mill_P	**831,936**	26,484	46,325	52,432	79,715	99,415	118,812	111,013	94,492	83,002	59,410	33,957	26,880
SR_Pavant III_P	**2,686,563**	111,395	134,597	228,283	257,419	312,381	326,190	313,964	299,310	261,828	215,287	136,955	88,955
SR_Prineville_P	**1,772,986**	60,175	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,034
SR_Sigurd_P	**2,905,614**	0	0	0	0	0	23,671	660,236	605,233	565,052	458,516	322,228	270,678
Total Long Term Firm Solar Purchases	**29,276,799**	**1,236,034**	**1,472,372**	**2,246,646**	**2,518,075**	**2,942,439**	**3,146,785**	**3,688,242**	**3,432,133**	**3,078,876**	**2,451,256**	**1,712,562**	**1,351,377**
Long Term Firm Wind Purchases													
WD_Cedar Springs_P	**11,723,272**	1,348,848	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
WD_Cedar Springs III_P	**8,908,094**	1,025,293	832,068	784,236	772,111	631,271	565,347	564,366	445,199	628,829	828,668	811,823	1,018,881
WD_Combine Hills_P	**5,369,070**	372,722	451,621	547,613	547,338	465,613	400,323	451,806	378,748	357,771	372,201	456,360	566,954
WD_Rock River_P	**3,978,379**	647,624	502,957	528,679	435,960	284,843	262,622	181,185	193,222	262,771	490,382	188,135	0
WD_Three Buttes_P	**20,662,793**	2,790,662	1,806,920	2,135,555	1,618,738	1,425,615	1,202,984	807,053	950,560	1,186,425	1,734,559	2,352,374	2,651,346
WD_Top of the World_P	**40,686,139**	5,436,528	3,612,747	4,244,159	3,270,671	2,907,362	2,399,809	1,720,419	1,872,120	2,296,835	3,513,194	4,491,633	4,920,662
WD_Wolverine Creek_P	**10,259,067**	760,539	888,634	1,132,687	1,040,512	787,597	844,716	669,522	637,856	752,718	827,853	962,861	953,572
Total Long Term Firm Wind Purchases	**101,586,814**	**12,382,216**	**9,190,148**	**10,405,173**	**8,701,365**	**7,333,126**	**6,419,682**	**5,137,134**	**5,063,696**	**6,312,848**	**8,857,391**	**10,331,529**	**11,452,507**
Long Term Firm Hydro Purchases													
Douglas - Wells_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Grant Wanapum Dev_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Grant Priest Rapids Dev_P	**2,072,011**	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668
Grant Reasonable_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Meaningful Priority_P	**25,591,632**	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636
Total Long Term Firm Hydro Purchases	**27,663,643**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**
Long Term Firm Other Purchases													
APS Supp Coal_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Supp Other_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Deseret Purchase_P	**33,411,787**	2,792,683	2,843,537	2,655,766	2,590,568	2,513,634	2,552,753	2,979,150	2,979,150	2,947,854	2,946,550	2,674,022	2,936,119
CoolKeeper Reserve_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Eagle Mountain-UAMPS1626656_P	**546,803**	16,316	15,456	17,263	17,566	16,566	68,739	118,561	120,073	82,257	0	35,667	38,341
Eagle Mountain-UAMPS1626657_P	**2,068,850**	140,576	125,592	108,610	111,251	137,604	215,863	318,185	287,362	158,816	156,349	118,011	190,629
Gemstate Purchase_P	**1,717,824**	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Hurricane Purchase_P	**165,480**	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790
MacCorp Buythru_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
MagCorp Reserves_P	**4,828,040**	401,000	392,980	401,000	409,020	401,000	409,020	413,030	392,980	388,970	372,930	433,080	413,030
Monsanto Buythru_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Monsanto Reserves_P	**20,000,000**	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Nucor Reserve_P	**7,129,800**	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
PGE Cove Replacement_P	**154,785**	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Small East Purchase_P	**14,288**	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
GEO_Soda Lake_P	**8,293,091**	822,675	726,731	767,167	706,207	682,902	572,441	516,487	545,410	595,644	725,349	782,467	849,611
Biomass One_NonGen_P	**(1,241,584)**	0	0	0	0	(626,892)	(614,693)	0	0	0	0	0	0
Total Long Term Firm Other Purchases	**77,089,163**	**6,605,080**	**6,536,166**	**6,381,635**	**6,266,441**	**5,556,705**	**5,635,983**	**6,777,296**	**6,756,835**	**6,605,352**	**6,632,993**	**6,475,113**	**6,859,562**
Total Long Term Firm Purchases	**235,616,418**	**22,528,634**	**19,503,990**	**21,338,758**	**19,791,185**	**18,137,574**	**17,507,754**	**17,907,976**	**17,557,967**	**18,302,379**	**20,246,944**	**20,824,508**	**21,968,750**

Solar Qualifying Facilities													
SR_Oregon CO Post-MSP_QF	**2,300,677**	77,816	111,034	162,715	227,354	268,324	306,338	316,611	288,014	228,682	160,007	82,963	70,817
SR_Oregon WM Post-MSP_QF	**18,241,080**	616,969	880,342	1,290,101	1,802,595	2,127,430	2,428,826	2,510,274	2,283,543	1,813,121	1,268,624	657,777	561,480
SR_Utah Post-MSP_QF	**10,247,886**	698,791	728,593	879,205	912,885	993,150	1,011,417	961,497	945,082	895,465	834,750	721,194	665,857
SR_Chiloquin_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SR_Enterprise I_UT_QF	**12,563,620**	617,060	756,869	980,643	1,117,040	1,257,239	1,382,201	1,554,604	1,501,679	1,181,692	958,192	710,651	545,749
SR_Escalante I_UT_QF	**11,601,699**	565,497	685,083	883,730	1,015,842	1,191,042	1,306,249	1,436,464	1,391,658	1,094,914	874,325	648,325	508,570
SR_Escalante II_UT_QF	**10,921,956**	531,489	645,513	832,363	955,501	1,126,570	1,235,899	1,359,761	1,304,267	1,031,738	818,253	606,453	474,150
SR_Escalante III_UT_QF	**10,520,814**	517,551	627,998	806,130	929,680	1,098,976	1,206,562	1,321,201	1,268,973	1,003,181	750,478	555,442	434,642
SR_Glen Canyon A_UT_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SR_Glen Canyon B_UT_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SR_Granite Mountain East_UT_QF	**10,913,762**	548,826	618,770	895,200	990,553	1,158,652	1,258,453	1,338,832	1,261,327	978,568	810,799	585,874	467,909
SR_Granite Mountain West_UT_QF	**7,220,476**	363,517	409,549	593,814	657,018	766,608	830,757	887,222	834,460	645,109	536,218	387,167	309,035
SR_Iron Springs_UT_QF	**11,200,375**	634,276	666,108	897,183	1,017,894	1,130,821	1,283,101	1,346,598	1,318,720	1,006,219	817,161	582,281	500,011
SR_Pavant_UT_QF	**5,611,810**	208,301	240,534	410,490	470,172	563,656	662,527	772,098	721,479	602,883	450,433	279,646	229,591
SR_Pavant II_UT_QF	**4,310,018**	177,389	225,178	346,901	399,214	454,357	476,933	558,197	543,942	425,102	330,218	205,953	166,635
SR_Red Hills_UT_QF	**11,565,267**	484,032	621,327	787,699	1,034,403	1,204,545	1,240,487	1,530,453	1,463,983	1,326,490	812,004	594,449	465,395
SR_Sage I_WY_QF	**2,270,456**	80,679	79,891	190,158	206,003	234,995	262,709	337,883	333,611	208,547	155,711	104,870	75,399
SR_Sage II_WY_QF	**2,272,891**	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,977	208,784	155,870	105,000	75,469
SR_Sage III_WY_QF	**1,870,483**	68,007	66,563	157,053	167,907	192,623	214,874	275,731	272,050	172,117	130,624	88,886	64,050
SR_Sweetwater_WY_QF	**7,797,372**	259,240	374,746	567,021	689,492	814,365	985,566	1,121,978	1,038,739	815,928	628,052	300,112	202,134
SR_Three Peaks_UT_QF	**8,452,877**	411,976	477,957	625,721	834,509	860,254	911,132	1,042,847	998,463	794,907	672,624	450,021	372,466
SR_Tumbleweed_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Solar Qualifying Facilities	**149,883,520**	**6,942,181**	**8,296,040**	**11,496,488**	**13,634,285**	**15,678,816**	**17,267,036**	**19,010,493**	**18,103,968**	**14,433,446**	**11,164,343**	**7,667,064**	**6,189,359**
Wind Qualifying Facilities													
WD_Oregon Post-MSP_QF	**7,200,085**	516,989	469,240	690,448	782,327	721,027	775,598	684,669	652,282	479,718	462,384	467,492	497,910
WD_Chopin_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_Five Pine_ID_QF	**8,399,980**	515,184	843,295	749,871	802,886	485,844	529,260	630,392	591,216	751,568	738,975	881,157	880,333
WD_Latigo Wind Park_UT_QF	**9,672,433**	1,007,976	917,725	1,119,717	895,550	857,781	745,592	682,684	563,374	621,378	790,071	708,277	762,309
WD_Monticello_UT_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_Mountain Wind 1_WY_QF	**8,916,081**	1,397,706	1,044,898	869,816	693,033	479,607	498,327	410,860	440,933	454,827	672,574	927,984	1,025,516
WD_Mountain Wind 2_WY_QF	**13,895,032**	2,038,486	1,566,199	1,352,529	1,078,715	750,862	890,296	761,456	734,168	757,712	1,009,556	1,435,298	1,519,756
WD_North Point_ID_QF	**18,786,578**	1,081,867	1,817,410	1,672,825	1,801,611	1,084,057	1,202,040	1,464,552	1,465,393	1,786,186	1,717,960	1,871,544	1,821,134
WD_Oregon Wind Farm_OR_QF	**12,468,786**	729,862	971,741	1,115,635	1,312,367	1,260,504	1,201,740	1,261,215	1,114,408	919,425	735,728	801,715	1,044,447
WD_Orem Family_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_Pioneer Wind Park I_WY_QF	**10,639,652**	1,303,917	924,898	1,187,446	905,027	704,142	650,577	649,784	680,906	450,437	820,675	1,263,591	1,098,250
WD_Power County North_ID_QF	**5,460,338**	415,705	548,470	525,350	519,896	350,949	344,576	370,353	360,111	380,493	511,430	530,622	602,381
WD_Power County South_ID_QF	**4,865,045**	367,049	482,868	474,030	482,998	302,559	306,289	327,761	335,462	336,896	447,464	479,427	522,240
WD_Spanish Fork 2_UT_QF	**2,754,893**	217,428	177,317	204,533	160,625	154,092	210,748	289,637	315,766	271,043	242,506	250,579	260,620
WD_Threemile Canyon_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Wind Qualifying Facilities	**103,058,904**	**9,592,169**	**9,764,061**	**9,962,201**	**9,435,034**	**7,151,426**	**7,355,043**	**7,533,363**	**7,254,020**	**7,209,682**	**8,149,323**	**9,617,687**	**10,034,896**
Other Qualifying Facilities													
California Pre Merger Pre-MSP_QF	**981,258**	91,344	121,650	139,635	189,175	178,961	121,479	40,661	13,623	9,962	9,370	16,818	48,582
California Post Merger Pre-MSP_QF	**29,542**	3,186	3,043	3,025	3,083	2,638	2,325	2,638	1,854	1,693	1,436	2,505	2,115
California Post Merger Post-MSP_QF	**1,456,200**	121,787	112,517	125,199	121,035	121,787	121,035	123,545	123,545	119,277	123,545	119,381	123,545
Idaho Pre Merger Pre-MSP_QF	**4,958,064**	344,783	308,524	392,179	443,898	588,668	585,708	527,676	348,862	344,348	322,121	383,309	367,989
Idaho Post Merger Pre-MSP_QF	**120,952**	5,666	5,917	13,514	18,531	11,795	14,462	13,405	9,064	7,353	6,781	8,797	5,666
Idaho Post Merger Post-MSP_QF	**2,751,508**	236,038	225,933	210,794	199,697	178,158	184,294	244,859	239,987	239,726	237,899	233,686	320,438
Oregon Pre Merger Pre-MSP_QF	**8,408,916**	714,509	661,242	742,175	851,029	849,743	758,373	666,101	666,393	721,883	572,965	533,515	670,985
Oregon Post Merger Pre-MSP_QF	**584,796**	47,831	41,135	61,541	100,349	97,645	84,416	31,946	18,992	18,727	12,349	27,155	42,711
Oregon Post Merger Post-MSP_QF	**14,109,749**	984,473	954,895	1,131,155	1,282,452	1,414,223	1,352,006	1,349,990	1,346,342	1,301,636	1,121,534	903,321	967,723
Utah N Post Merger Post-MSP_QF	**632,177**	46,396	49,136	55,415	53,863	62,149	61,998	48,793	55,340	48,604	50,933	53,978	45,574
Utah S Post Merger Post-MSP_QF	**632,177**	46,396	49,136	55,415	53,863	62,149	61,998	48,793	55,340	48,604	50,933	53,978	45,574
Washington Post Merger Post-MSP_QF	**218,736**	0	0	19	8,001	21,996	37,135	51,373	52,945	35,398	11,871	0	0
Wyoming Pre Merger Pre-MSP_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Wyoming Post Merger Pre-MSP_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Wyoming Post Merger Post-MSP_QF	**86,184**	10,091	8,471	10,115	6,257	4,967	2,992	8,382	7,360	4,207	5,944	6,878	10,520
Biomass One_OR_QF	**16,515,565**	1,240,650	1,202,754	1,328,737	1,605,809	1,642,614	1,605,809	1,455,965	1,407,485	1,392,619	1,454,920	1,426,918	751,284
DCFP_OR_QF	**117,193**	3,577	4,372	3,513	2,866	3,059	4,880	19,721	22,137	26,416	12,083	7,259	7,311
Roseburg Dillard_CA_QF	**982,171**	43,523	50,277	26,541	102,556	104,709	88,024	164,486	131,434	66,115	76,189	75,916	52,401
Sunnyside Base_UT_QF	**25,446,689**	1,926,944	1,794,251	2,230,743	1,509,783	2,271,849	2,278,852	2,438,937	2,404,628	2,262,028	1,952,501	2,278,541	2,097,630
Sunnyside Additional_UT_QF	**5,496,514**	411,090	388,623	462,527	451,598	469,488	470,673	497,779	491,970	467,826	474,327	470,621	439,990
Tesoro_UT_QF	**296,096**	46,096	34,206	27,450	19,189	25,292	6,946	13,491	20,976	19,011	19,842	20,127	43,471
Total Other Qualifying Facilities	**83,824,486**	**6,324,381**	**6,016,080**	**7,019,693**	**7,023,032**	**8,111,890**	**7,843,402**	**7,748,542**	**7,418,278**	**7,135,433**	**6,517,542**	**6,622,704**	**6,043,510**
Total Qualifying Facilities	**336,766,909**	**22,858,731**	**24,076,181**	**28,478,382**	**30,092,352**	**30,942,132**	**32,465,481**	**34,292,398**	**32,776,265**	**28,778,562**	**25,831,208**	**23,907,454**	**22,267,764**

Exchanges													
APS Exchange In-PPGC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Exchange In-FC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Exchange Out-PPGC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Exchange Out-FC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
PSCol Exchange In_P	**5,400,000**	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCol Exchange Out_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_SCL State Line Generation_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SCL-Stateline Delivery_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SCL-Stateline Losses_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SCL-Stateline Reserves_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Exchanges	**5,400,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**
Short Term Firm Purchases													
STF Borah_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF COB_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Colorado_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Four Corners_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mead_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mid Columbia_P	**14,768,640**	1,621,000	1,556,160	1,750,680	0	0	1,216,800	2,912,000	2,912,000	2,800,000	0	0	0
STF Mona_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Palo Verde_P	**678,500**	247,250	207,000	224,250	0	0	0	0	0	0	0	0	0
STF PP-GC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming East_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming North_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Short Term Firm Purchases	**15,447,140**	**1,868,250**	**1,763,160**	**1,974,930**	**0**	**0**	**1,216,800**	**2,912,000**	**2,912,000**	**2,800,000**	**0**	**0**	**0**
System Balancing Purchases													
COB	**13,650,632**	256,796	176,618	1,541,659	766,329	2,532,784	1,598,378	1,986,504	1,277,522	563,293	831,396	743,288	1,376,064
Four Corners	**18,532,479**	1,765,251	2,892,183	4,051,845	1,279,491	1,076,258	217,643	872,158	676,196	352,326	1,379,366	1,484,561	2,485,201
Mead	**5,635,494**	365,486	777,555	348,436	294,096	456,275	412,248	894,509	413,420	443,981	380,806	169,957	678,726
Mid Columbia	**69,840,592**	2,961,318	1,414,822	962,531	2,238,265	13,451,364	12,840,011	13,022,595	13,900,634	3,546,501	2,252,822	1,434,611	1,815,117
Mona	**8,736,656**	1,083,486	690,394	803,185	562,467	661,458	92,264	866,660	493,322	346,124	1,016,204	1,190,417	930,675
NOB	**11,488,657**	0	0	136,696	1,682,517	313,457	156,723	2,190,741	3,482,419	1,332,912	63,056	193,975	1,936,162
Palo Verde	**2,469,641**	675,237	564,123	515,725	79,395	79,395	79,395	79,395	79,395	79,395	79,395	79,395	79,395
Emergency Purchases	**1,933,211**	0	0	0	59,583	775,436	72,286	473,946	47,070	354,072	67,489	16,636	66,692
EIM Imports/Exports	**(59,250,810)**	(3,445,870)	(3,105,010)	(6,863,178)	(6,863,641)	(7,467,599)	(3,035,622)	(7,434,719)	(7,740,230)	(4,243,730)	(2,826,239)	(2,722,603)	(3,502,369)
Total System Balancing Purchases	73,036,553	**3,661,704**	**3,410,686**	**1,496,900**	**98,501**	**11,878,828**	**12,433,327**	**12,951,790**	**12,629,748**	**2,774,875**	**3,244,295**	**2,590,237**	**5,865,663**
Total Purchase Expenses	**666,267,021**	**51,367,319**	**49,204,017**	**53,738,969**	**50,432,038**	**61,408,533**	**64,073,362**	**68,514,163**	**66,325,980**	**53,105,815**	**49,772,447**	**47,772,200**	**50,552,178**
Wheeling Expenses													
Wheeling Expenses - East	**23,995,497**	2,219,922	2,390,245	2,269,358	2,207,351	1,635,627	1,914,090	1,728,308	1,692,073	2,055,323	1,763,481	2,190,283	1,929,437
Wheeling Expenses - West	**116,275,997**	9,811,383	9,417,188	9,833,558	9,701,806	8,965,309	9,514,241	9,218,342	9,372,759	9,720,813	9,853,080	10,010,925	10,856,596
Total Wheeling Expenses	**140,271,494**	**12,031,304**	**11,807,432**	**12,102,916**	**11,909,157**	**10,600,935**	**11,428,331**	**10,946,650**	**11,064,831**	**11,776,136**	**11,616,561**	**12,201,208**	**12,786,032**

Coal Fuel Costs														
Cholla 4	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip 3	**6,743,536**	724,525	460,344	505,129	577,625	380,624	579,040	685,894	730,984	620,364	444,777	340,907	693,325
Colstrip 4	**7,257,302**	709,552	447,732	502,498	610,693	322,258	514,926	794,727	836,314	681,105	440,641	651,044	745,813
Craig 1	**8,763,907**	824,967	622,614	691,539	747,355	293,600	627,907	824,252	858,234	788,247	797,021	756,402	931,770
Craig 2	**9,161,302**	873,615	708,999	791,182	670,943	408,898	732,671	702,234	890,943	845,996	854,299	820,614	860,910
Dave Johnston 1	**8,434,015**	730,346	705,893	775,742	708,441	775,808	716,878	743,263	776,284	278,650	778,026	705,531	739,154
Dave Johnston 2	**7,754,005**	709,832	722,008	793,552	587,225	533,917	430,615	661,715	652,029	651,369	808,199	688,034	515,510
Dave Johnston 3	**15,400,725**	1,637,875	1,442,794	619,873	1,072,752	1,537,518	863,880	1,215,356	1,400,568	1,450,972	1,516,502	1,244,365	1,398,272
Dave Johnston 4	**23,843,984**	2,298,785	2,228,426	2,430,399	1,678,943	1,618,128	2,189,781	1,964,259	2,207,277	2,170,358	1,923,463	1,172,154	1,962,012
Hayden 1	**6,518,462**	572,263	473,256	539,817	527,516	621,051	565,885	626,932	549,133	335,977	508,879	603,705	594,048
Hayden 2	**4,353,641**	362,981	276,043	319,885	388,815	502,406	428,546	432,920	343,132	265,390	256,070	343,396	434,056
Hunter 1	**41,173,406**	3,921,773	2,967,374	1,687,380	2,658,292	2,726,535	3,616,013	3,963,715	4,057,193	3,716,762	3,976,571	3,805,619	4,076,179
Hunter 2	**26,065,012**	2,875,507	2,130,482	2,129,285	1,385,982	1,852,422	2,193,159	2,482,615	1,816,154	2,040,061	2,073,104	2,584,924	2,501,317
Hunter 3	**50,561,913**	4,782,836	3,631,652	3,670,041	2,350,165	3,943,947	4,171,685	4,735,171	5,074,824	4,417,382	4,436,911	4,702,258	4,645,042
Huntington 1	**60,145,415**	5,457,542	3,979,840	3,943,189	4,991,971	3,989,142	4,395,989	6,433,773	6,127,715	4,468,420	5,220,835	4,901,357	6,235,641
Huntington 2	**43,390,630**	3,929,290	2,084,775	2,489,016	3,159,220	2,572,348	2,930,819	4,826,207	5,397,127	4,065,968	1,907,699	4,246,904	5,781,257
Jim Bridger 1	**44,451,387**	2,984,935	2,618,409	2,894,337	3,781,950	1,887,600	2,781,931	5,563,463	5,610,212	4,748,675	3,814,928	4,309,198	3,455,750
Jim Bridger 2	**48,519,097**	3,581,861	3,031,949	3,194,427	2,376,725	2,925,493	3,719,856	5,817,880	5,208,470	5,028,788	4,904,166	4,318,646	4,410,836
Jim Bridger 3	**38,769,170**	2,568,113	2,108,772	2,558,268	3,387,973	2,487,063	3,303,153	4,537,483	5,111,074	4,069,382	2,515,083	3,165,380	2,957,427
Jim Bridger 4	**35,126,601**	2,819,482	2,260,864	2,640,948	2,947,085	2,444,086	2,613,908	4,508,884	4,281,763	2,022,148	2,338,833	2,967,531	3,281,069
Naughton 1	**32,861,448**	3,159,592	2,735,409	2,816,577	2,610,445	1,778,745	2,646,754	2,908,541	2,922,312	2,992,532	2,995,208	2,413,914	2,881,418
Naughton 2	**44,989,355**	4,267,375	3,608,743	3,623,729	3,836,804	3,501,728	3,440,209	3,759,965	3,935,783	3,716,798	4,053,936	3,878,647	3,365,638
Wyodak	**29,331,659**	2,665,998	2,596,607	2,858,330	2,549,670	2,837,949	2,204,888	2,706,063	2,551,464	2,386,598	2,416,783	2,007,256	1,550,053
Total Coal Fuel Costs	**593,615,974**	**52,459,045**	**41,842,983**	**42,475,143**	**43,606,590**	**39,941,264**	**45,668,492**	**60,895,310**	**61,338,987**	**51,761,943**	**48,981,933**	**50,627,786**	**54,016,497**
Gas Fuel Costs													
GS_Chehalis	**39,191,777**	5,601,806	6,850,667	5,000,964	399,342	0	526,745	3,952,845	3,842,001	3,053,599	3,995,823	1,442,305	4,525,679
GS_Currant Creek	**43,149,230**	3,945,536	5,068,986	3,965,335	2,567,360	527,000	2,866,258	5,005,347	3,611,548	3,760,304	2,560,237	4,822,141	4,449,178
GS_Currant Creek DF	**2,618,880**	246,907	302,755	237,606	151,756	33,290	155,738	310,092	217,979	206,945	159,648	290,171	305,993
GS_Gadsby 1	**1,500,904**	113,808	138,029	123,398	38,707	21,139	77,313	302,329	261,884	132,164	74,250	74,174	143,708
GS_Gadsby 2	**1,544,554**	106,788	111,251	105,308	60,446	63,419	96,089	273,185	250,801	141,443	78,103	97,828	159,893
GS_Gadsby 3	**2,501,997**	242,267	270,207	243,593	79,156	91,727	153,064	321,208	322,474	192,552	121,909	170,161	293,680
GS_Gadsby 4	**1,227,107**	210,235	101,469	0	27,130	2,266	31,215	208,132	218,050	123,748	69,923	68,870	166,067
GS_Gadsby 5	**1,178,719**	210,235	111,616	0	11,696	3,626	29,379	207,518	222,175	118,602	53,455	60,493	149,925
GS_Gadsby 6	**1,280,244**	210,235	142,056	0	14,970	0	22,034	215,727	226,455	139,508	61,666	77,286	170,307
GS_Hermiston 1	**13,465,460**	3,369,204	2,252,593	1,701,740	0	0	0	1,890,465	2,101,904	2,149,553	0	0	0
GS_Hermiston 2	**8,258,348**	0	0	0	1,300,107	301,995	585,250	0	0	0	1,650,244	1,995,280	2,425,472
GS_Lake Side 1	**50,609,195**	4,519,987	5,829,564	4,614,648	2,060,159	808,606	3,341,692	5,686,945	5,732,585	5,176,499	4,396,507	4,517,300	3,924,704
GS_Lake Side 1 DF	**1,411,980**	60,137	0	4,542	56,324	31,645	129,431	282,132	258,791	164,278	111,537	136,720	176,443
GS_Lake Side 2	**59,058,338**	6,060,646	6,527,223	5,744,565	3,750,550	1,805,471	3,893,581	5,414,014	5,368,840	4,684,680	4,953,688	4,533,242	6,321,837
GS_Lake Side 2 DF	**1,917,085**	67,549	5,857	30,896	108,461	55,289	121,837	333,354	318,119	197,238	168,692	169,799	339,995
GS_Naughton 3	**6,328,837**	202,467	160,436	199,615	108,007	168,133	400,542	1,267,035	1,147,091	551,778	433,359	369,884	1,320,489
Total Gas Fuel Costs	**235,242,654**	**25,167,807**	**27,872,708**	**21,972,211**	**10,734,169**	**3,913,607**	**12,430,168**	**25,670,328**	**24,100,696**	**20,792,893**	**18,889,042**	**18,825,655**	**24,873,372**
Gas Financials													
GS_Clay Basin Gas Storage	**(588,564)**	(334,019)	(307,763)	(216,982)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	2,850	(98,348)
GS_Gas Physical - Chehalis	**0**	0	0	0	0	0	0	0	0	0	0	0	0
GS_Gas Physical - East	**84,248**	26,737	25,270	32,240	0	0	0	0	0	0	0	0	0
GS_Gas Physical - Hermiston	**(500,971)**	(105,851)	(83,235)	(56,541)	(25,945)	(23,006)	(23,393)	(50,730)	(49,843)	(45,141)	(37,288)	0	0
GS_Gas Swaps - Chehalis	**(880,780)**	(649,915)	(319,060)	88,195	0	0	0	0	0	0	0	0	0
GS_Gas Swaps - East	**(19,056,887)**	(3,887,012)	(2,992,150)	(1,327,188)	(534,300)	(308,760)	(399,300)	(2,547,968)	(2,611,285)	(2,249,700)	18,135	(364,800)	(1,852,560)
GS_Gas Swaps - Hermiston	**0**	0	0	0	0	0	0	0	0	0	0	0	0
GS_Pipeline Lateral - Chehalis	**601,800**	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150
GS_Pipeline Main - Chehalis	**10,697,195**	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433
GS_Pipeline Lateral - Currant Creek	**1,292,395**	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700
GS_Pipeline - Hermiston	**2,533,944**	212,720	204,708	212,720	210,049	212,720	210,049	212,720	212,720	210,049	212,720	210,049	212,720
GS_Pipeline - Kern River Gas	**2,989,350**	253,890	229,320	253,890	245,700	253,890	245,700	253,890	253,890	245,700	253,890	245,700	253,890
GS_Pipeline - Lake Side 2	**5,334,796**	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566
GS_Pipeline Lateral - Lake Side	**2,353,029**	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086
GS_Pipeline - Naughton	**2,564,970**	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748
GS_Pipeline Reservation Fees	**801,834**	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820
GS_Pipeline - Southern System Expansion	**5,635,526**	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627
0													
Total Gas Financials	**13,861,885**	**(2,043,321)**	**(802,780)**	**1,426,463**	**2,387,876**	**2,627,215**	**2,525,428**	**360,284**	**297,853**	**653,279**	**2,939,828**	**2,533,928**	**955,831**

Geothermal Fuel Costs													
GEO_Blundell 1	**3,170,429**	309,265	279,336	279,336	280,341	300,637	286,715	271,085	284,381	291,794	272,164	151,321	164,054
GEO_Blundell 2	**1,381,645**	147,909	133,596	133,596	130,074	120,972	104,090	107,501	107,531	117,113	126,023	70,539	82,702
Total Geothermal Fuel Costs	**4,552,074**	**457,175**	**412,932**	**412,932**	**410,415**	**421,609**	**390,805**	**378,586**	**391,912**	**408,907**	**398,186**	**221,859**	**246,757**
Total Generation Fuel Costs	**847,272,587**	**76,040,705**	**69,325,843**	**66,286,749**	**57,139,050**	**46,903,696**	**61,014,893**	**87,304,507**	**86,129,448**	**73,617,022**	**71,208,989**	**72,209,228**	**80,092,456**
NPC	**1,402,959,155**	**113,011,252**	**110,946,867**	**116,618,187**	**107,008,968**	**107,903,680**	**120,937,475**	**138,994,763**	**132,317,737**	**109,984,159**	**111,706,200**	**112,211,552**	**121,318,315**

Rocky Mountain Power
Exhibit 10.3
Docket No. 20000-___-ER-23
Witness: Ramon J. Mitchell

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Cost GRID Test Report

March 2023

PacifiCorp

GRID Test NPC Report

Net Power Cost Analysis

$

12 months ended December 2021	01/21-12/21	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,532,217	735,605	518,304	481,626	474,039	433,303	595,216	737,682	733,885	726,030	643,094	706,458	746,974
Hurricane Sale	7,474	623	623	623	623	623	623	623	623	623	623	623	623
Leaning Juniper Revenue	105,254	7,601	7,384	9,260	5,355	4,684	6,043	14,266	16,102	10,939	7,961	6,724	8,936
Total Long Term Firm Sales	**7,644,944**	**743,829**	**526,310**	**491,509**	**480,016**	**438,610**	**601,882**	**752,571**	**750,609**	**737,591**	**651,677**	**713,806**	**756,532**
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	21,354,660	3,522,890	2,974,080	3,095,370	1,977,600	1,958,400	1,977,600	-	-	-	1,971,460	1,905,800	1,971,460
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	7,750,000	1,277,800	1,202,400	1,345,800	338,000	325,000	338,000	-	-	-	985,000	953,000	985,000
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	23,424,050	3,801,450	3,397,800	3,751,050	1,877,100	1,834,950	1,877,100	-	-	-	2,320,550	2,243,500	2,320,550
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	**52,528,710**	**8,602,140**	**7,574,280**	**8,192,220**	**4,192,700**	**4,118,350**	**4,192,700**	**-**	**-**	**-**	**5,277,010**	**5,102,300**	**5,277,010**
System Balancing Sales													
COB	29,651,914	3,332,735	2,357,695	1,898,661	1,035,907	1,048,019	1,760,434	2,240,054	2,231,577	2,100,152	3,520,890	3,894,654	4,231,137
Four Corners	39,704,708	3,303,662	3,448,953	2,009,392	1,765,495	1,113,323	640,820	6,174,110	5,483,323	5,864,117	3,124,169	3,104,731	3,672,614
Mead	32,132,100	4,416,682	3,016,064	1,456,847	948,624	1,219,709	1,728,477	2,297,774	3,511,400	3,195,582	3,421,497	3,562,410	3,357,034
Mid Columbia	44,001,091	3,786,533	803,610	528,753	2,209,685	1,371,110	2,444,523	6,701,841	7,389,368	7,080,796	4,269,499	4,171,327	3,244,045
Mona	19,491,384	1,825,358	547,950	233,377	784,958	995,043	1,432,010	2,289,681	2,400,963	5,463,776	1,324,799	1,133,092	1,060,377
NOB	6,320,250	-	14,777	588,915	784,080	22,523	47,501	1,252,386	1,907,945	654,601	26,842	11,956	1,008,724
Palo Verde	29,896,139	447,443	(13,689)	18,916	942,147	1,047,494	1,457,472	8,639,102	9,586,551	6,248,536	514,470	363,107	644,590
Trapped Energy	1,403	-	-	-	-	-	-	-	-	-	-	1,403	-
Total System Balancing Sales	**201,198,989**	**17,112,413**	**10,175,360**	**6,734,861**	**8,470,896**	**6,817,222**	**9,511,238**	**29,594,947**	**32,511,127**	**30,607,559**	**16,202,167**	**16,242,679**	**17,218,521**
Total Special Sales For Resale	**261,372,642**	**26,458,383**	**18,275,950**	**15,418,589**	**13,143,612**	**11,374,182**	**14,305,819**	**30,347,518**	**33,261,736**	**31,345,151**	**22,130,854**	**22,058,785**	**23,252,063**

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,369,068	372,723	451,621	547,613	547,338	465,612	400,323	451,804	378,748	357,771	372,201	456,360	566,954
Cove Mountain Solar	3,863,906	185,318	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,150
Cove Mountain Solar II	343,571	28,534	28,675	28,713	28,701	28,534	28,701	28,624	28,624	28,609	28,624	28,609	28,624
Deseret Purchase	33,416,953	2,792,679	2,843,532	2,655,765	2,590,568	2,494,076	2,584,049	2,979,142	2,979,142	2,947,847	2,946,543	2,667,501	2,936,112
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,615,653	156,892	141,048	125,873	128,817	154,170	284,603	436,745	407,435	241,073	156,349	153,679	228,968
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Hunter Solar	7,122,324	374,917	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,602
Hurricane Purchase	165,480	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	4,828,040	401,000	392,980	401,000	409,020	401,000	409,020	413,030	392,980	388,970	372,930	433,080	413,030
Milican Solar	2,646,179	68,661	138,221	204,961	257,983	306,199	333,290	375,334	331,656	266,914	174,771	111,940	76,250
Milford Solar	7,081,219	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	394,020	310,716
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	860,113	27,048	47,956	54,277	82,521	102,914	122,994	114,920	97,817	85,923	61,501	35,152	27,089
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	2,693,193	112,247	140,376	230,428	259,149	310,804	322,999	305,697	292,254	260,260	214,705	137,146	107,129
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,795,505	82,013	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,717
Rock River Wind	3,949,010	647,624	502,957	528,679	435,960	284,843	262,621	181,185	193,222	262,771	490,382	158,766	-
Sigurd Solar	2,905,571	-	-	-	-	-	23,671	660,236	605,234	565,052	458,516	322,228	270,634
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	8,293,074	822,678	726,727	767,161	706,202	682,900	572,444	516,493	545,404	595,645	725,353	782,463	849,605
Three Buttes Wind	20,662,796	2,790,663	1,806,921	2,135,557	1,618,738	1,425,615	1,202,984	807,052	950,561	1,186,424	1,734,559	2,352,376	2,651,346
Top of the World Wind	40,686,138	5,436,527	3,612,759	4,244,151	3,270,658	2,907,364	2,399,806	1,720,417	1,872,120	2,296,841	3,513,203	4,491,632	4,920,662
Wolverine Creek Wind	10,259,065	760,539	888,633	1,132,686	1,040,512	787,596	844,716	669,522	637,857	752,718	827,852	962,861	953,573
Long Term Firm Purchases Total	**209,204,921**	**20,224,670**	**17,206,098**	**19,037,430**	**17,490,397**	**16,441,523**	**15,849,432**	**15,598,304**	**15,248,923**	**15,998,428**	**17,943,153**	**18,484,599**	**19,681,966**

Qualifying Facilities														
QF California	2,467,000	216,317	237,210	267,860	313,293	303,385	244,839	166,844	139,023	130,932	134,351	138,704	174,243
QF Idaho	7,830,524	586,487	540,373	616,487	662,125	778,621	784,464	785,940	597,914	591,427	566,801	625,791	694,093
QF Oregon	50,845,304	2,958,588	3,117,888	4,078,136	5,046,106	5,478,394	5,705,557	5,559,591	5,255,566	4,563,767	3,597,862	2,672,224	2,811,626
QF Utah	11,512,240	791,583	826,865	990,034	1,020,610	1,117,447	1,135,413	1,059,082	1,055,762	992,673	936,615	829,151	757,005
QF Washington	218,736	-	-	19	8,001	21,996	37,135	51,373	52,945	35,398	11,871	-	-
QF Wyoming	86,184	10,091	8,471	10,115	6,257	4,967	2,992	8,382	7,360	4,207	5,944	6,878	10,520
Biomass One QF	15,273,904	1,240,648	1,202,763	1,328,736	1,605,813	1,011,582	995,142	1,455,970	1,407,489	1,392,627	1,454,930	1,426,922	751,283
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	117,193	3,577	4,372	3,513	2,866	3,059	4,880	19,721	22,137	26,416	12,083	7,259	7,310
Enterprise Solar I QF	12,563,411	617,060	756,870	980,643	1,117,038	1,257,240	1,382,198	1,554,604	1,501,679	1,181,692	957,986	710,651	545,749
Escalante Solar I QF	11,601,502	565,498	685,084	883,730	1,015,842	1,191,044	1,306,249	1,436,464	1,391,659	1,094,914	874,125	648,324	508,570
Escalante Solar II QF	10,921,713	531,489	645,513	832,362	955,502	1,126,572	1,235,898	1,359,761	1,304,268	1,031,738	818,007	606,453	474,150
Escalante Solar III QF	10,520,640	517,551	627,997	806,129	929,679	1,098,975	1,206,563	1,321,201	1,268,974	1,003,181	750,305	555,442	434,642
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,399,980	515,184	843,295	749,871	802,885	485,845	529,260	630,392	591,216	751,568	738,975	881,157	880,334
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,913,761	548,826	618,770	895,198	990,554	1,158,651	1,258,453	1,338,832	1,261,328	978,568	810,799	585,874	467,909
Granite Mountain West Solar QF	7,220,477	363,517	409,549	593,815	657,017	766,608	830,760	887,222	834,460	645,109	536,218	387,167	309,035
Iron Springs Solar QF	11,200,371	634,276	666,108	897,183	1,017,893	1,130,820	1,283,100	1,346,598	1,318,721	1,006,219	817,161	582,281	500,011
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,740	1,007,477	917,570	1,126,955	897,120	856,897	745,979	673,722	567,152	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,916,080	1,397,705	1,044,898	869,816	693,034	479,607	498,327	410,860	440,933	454,827	672,574	927,984	1,025,515
Mountain Wind 2 QF	13,895,033	2,038,485	1,566,199	1,352,529	1,078,715	750,861	890,296	761,455	734,168	757,712	1,009,557	1,435,299	1,519,756
North Point Wind QF	18,786,576	1,081,867	1,817,411	1,672,826	1,801,611	1,084,057	1,202,040	1,464,551	1,465,394	1,786,186	1,717,960	1,871,542	1,821,132
Oregon Wind Farm QF	12,468,790	729,863	971,742	1,115,635	1,312,368	1,260,505	1,201,740	1,261,216	1,114,406	919,426	735,727	801,716	1,044,447
Pavant II Solar QF	4,310,019	177,389	225,179	346,901	399,215	454,358	476,933	558,197	543,942	425,101	330,218	205,953	166,635
Pioneer Wind Park I QF	10,639,652	1,303,917	924,899	1,187,446	905,027	704,142	650,577	649,784	680,906	450,438	820,675	1,263,591	1,098,250
Power County North Wind QF	5,460,338	415,705	548,470	525,351	519,896	350,950	344,576	370,353	360,112	380,493	511,430	530,622	602,381
Power County South Wind QF	4,865,045	367,049	482,868	474,030	482,998	302,560	306,289	327,761	335,462	336,896	447,464	479,428	522,241
Roseburg Dillard QF	982,170	43,523	50,277	26,541	102,556	104,709	88,024	164,486	131,433	66,116	76,189	75,916	52,402
Sage I Solar QF	2,270,456	80,679	79,891	190,158	206,003	234,995	262,709	337,883	333,611	208,547	155,711	104,870	75,399
Sage II Solar QF	2,272,891	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,976	208,784	155,870	105,000	75,469
Sage III Solar QF	1,870,483	68,007	66,563	157,054	167,907	192,623	214,874	275,730	272,050	172,117	130,624	88,886	64,050
Spanish Fork Wind 2 QF	2,754,893	217,428	177,317	204,533	160,626	154,092	210,749	289,636	315,766	271,043	242,505	250,579	260,620
Sunnyside QF	30,170,399	2,309,028	2,161,795	2,472,700	2,027,444	2,723,249	2,736,541	2,752,683	2,722,145	2,586,845	2,374,035	2,757,466	2,546,468
Sweetwater Solar QF	7,797,376	259,240	374,746	567,022	689,492	814,366	985,566	1,121,979	1,038,739	815,928	628,052	300,112	202,134
Tesoro QF	298,022	46,182	34,259	27,485	19,215	25,768	7,053	13,571	21,290	19,336	20,203	20,155	43,505
Three Peaks Solar QF	8,452,878	411,976	477,957	625,721	834,509	860,254	911,132	1,042,848	998,463	794,907	672,624	450,022	372,466
Utah Pavant Solar QF	5,611,720	208,301	240,534	410,490	470,172	563,656	662,527	772,097	721,480	602,883	450,433	279,646	229,501
Utah Red Hills Solar QF	11,565,119	484,032	621,327	787,698	1,034,405	1,204,547	1,240,486	1,530,453	1,463,983	1,326,491	812,004	594,449	465,244
Qualifying Facilities Total	**334,755,618**	**22,829,307**	**24,055,015**	**28,265,079**	**30,160,014**	**30,292,609**	**31,842,323**	**34,099,488**	**32,605,910**	**28,631,195**	**25,787,141**	**23,917,202**	**22,270,336**
Mid-Columbia Contracts													
Grant Reasonable	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Meaningful Priority	25,591,630	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636
Grant Surplus	2,072,011	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	**27,663,641**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**
Total Long Term Firm Purchases	**571,624,179**	**45,359,280**	**43,566,416**	**49,607,813**	**49,955,714**	**49,039,435**	**49,997,058**	**52,003,095**	**50,160,136**	**46,934,926**	**46,035,597**	**44,707,103**	**44,257,606**

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	**5,400,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	14,768,640	1,621,000	1,556,160	1,750,680	-	-	1,216,800	2,912,000	2,912,000	2,800,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	678,500	247,250	207,000	224,250	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF purchase subtotal	**15,447,140**	**1,868,250**	**1,763,160**	**1,974,930**	**-**	**-**	**1,216,800**	**2,912,000**	**2,912,000**	**2,800,000**	**-**	**-**	**-**
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	**15,447,140**	**1,868,250**	**1,763,160**	**1,974,930**	**-**	**-**	**1,216,800**	**2,912,000**	**2,912,000**	**2,800,000**	**-**	**-**	**-**
System Balancing Purchases													
COB	14,400,284	285,501	1,261,483	1,663,711	654,627	1,723,681	1,485,126	2,446,485	1,421,069	490,529	859,093	269,382	1,839,598
Four Corners	28,429,398	2,842,587	6,364,713	5,884,089	1,787,296	1,633,184	309,859	982,553	851,816	639,118	1,206,644	1,623,407	4,304,131
Mead	6,543,189	387,353	928,141	318,456	278,541	379,237	379,454	940,549	439,285	462,393	719,567	378,270	931,941
Mid Columbia	74,407,799	3,915,594	800,844	526,045	1,576,329	12,539,935	10,932,812	16,028,724	15,750,997	4,701,338	2,559,815	2,096,022	2,979,345
Mona	8,713,073	947,711	193,196	1,362,896	221,788	747,258	66,919	835,818	503,604	356,076	1,169,571	1,267,020	1,041,216
NOB	13,555,306	-	54,296	839,002	1,593,155	47,602	126,782	2,608,241	4,164,455	1,515,362	44,561	30,185	2,531,664
Palo Verde	3,291,208	1,912,292	661,767	450,253	9,223	39,536	-	-	2,543	8,368	40,836	155,432	10,958
EIM Imports/Exports	(59,250,810)	(3,445,870)	(3,105,010)	(6,863,178)	(6,863,641)	(7,467,599)	(3,035,622)	(7,434,719)	(7,740,230)	(4,243,730)	(2,826,239)	(2,722,603)	(3,502,369)
Emergency Purchases	1,904,827	-	-	-	59,287	773,282	72,269	451,177	44,688	354,008	67,468	16,629	66,017
Total System Balancing Purchases	**91,994,275**	**6,845,168**	**7,159,431**	**4,181,275**	**(683,394)**	**10,416,116**	**10,337,600**	**16,858,829**	**15,438,227**	**4,283,462**	**3,841,317**	**3,113,745**	**10,202,500**
Total Purchased Power & Net Interc	**684,465,594**	**54,522,699**	**52,939,007**	**56,214,017**	**49,722,320**	**59,905,551**	**62,001,457**	**72,223,924**	**68,960,363**	**54,468,388**	**50,326,914**	**48,270,848**	**54,910,106**

Wheeling & U. of F. Expense													
Firm Wheeling	138,233,270	11,846,758	11,639,521	11,941,445	11,705,073	10,378,573	11,220,154	10,774,214	10,929,786	11,622,523	11,445,797	12,073,700	12,655,725
C&T EIM Admin fee	2,038,227	184,546	167,911	161,471	204,085	222,363	208,177	172,436	135,045	153,613	170,764	127,508	130,308
ST Firm & Non-Firm	43,029	13,235	3,760	3,011	434	-	1,277	4,049	2,190	1,585	2,870	7,203	3,415
Total Wheeling & U. of F. Expense	**140,314,526**	**12,044,539**	**11,811,193**	**12,105,927**	**11,909,592**	**10,600,936**	**11,429,608**	**10,950,699**	**11,067,022**	**11,777,721**	**11,619,431**	**12,208,412**	**12,789,447**
Coal Fuel Burn Expense													
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	15,944,066	1,758,488	1,502,306	1,491,743	1,294,454	719,529	1,130,158	1,544,746	1,651,646	1,436,935	951,206	1,010,123	1,452,732
Craig	19,150,970	1,915,459	1,662,106	1,728,134	1,467,240	701,480	1,373,402	1,586,878	1,847,263	1,720,488	1,695,960	1,624,924	1,827,637
Dave Johnston	55,761,755	5,545,315	5,097,111	4,666,077	3,972,961	4,406,396	4,179,117	4,600,831	5,049,983	4,544,176	5,008,160	3,899,963	4,791,664
Hayden	11,314,790	1,092,517	971,852	996,901	891,991	1,119,222	980,957	1,054,345	890,611	583,886	745,023	962,052	1,025,432
Hunter	119,361,523	11,752,962	9,868,586	8,782,962	6,001,455	7,541,139	9,746,152	11,280,364	11,214,492	10,620,817	10,346,073	11,107,035	11,099,486
Huntington	99,922,532	9,902,243	8,280,046	7,685,095	7,137,019	5,729,828	6,704,581	10,577,674	10,714,065	7,672,838	6,652,417	8,067,526	10,799,200
Jim Bridger	160,568,885	10,891,597	11,572,897	12,951,734	11,209,268	8,629,348	10,713,340	21,122,415	20,810,479	14,798,137	11,635,424	13,336,149	12,898,097
Naughton	75,457,447	7,037,257	6,059,344	6,209,946	5,907,535	4,795,131	5,900,533	6,659,412	6,855,070	6,691,583	6,915,264	6,264,483	6,161,889
Wyodak	29,019,449	2,571,408	2,513,652	2,811,880	2,503,324	2,778,487	2,190,116	2,725,396	2,562,642	2,392,560	2,402,957	2,007,981	1,559,048
Total Coal Fuel Burn Expense	**586,501,418**	**52,467,246**	**47,527,899**	**47,324,471**	**40,385,246**	**36,420,561**	**42,918,356**	**61,152,062**	**61,596,250**	**50,461,421**	**46,352,485**	**48,280,236**	**51,615,184**
Gas Fuel Burn Expense													
Chehalis	38,103,671	2,474,830	1,122,065	1,924,565	2,320,703	20,136	1,745,829	4,774,064	4,709,339	4,661,488	5,007,935	4,525,362	4,817,356
Currant Creek	36,936,636	2,483,854	453,011	132,129	2,689,159	1,529,496	3,400,255	4,743,362	3,618,956	3,968,192	4,557,262	4,945,180	4,415,780
Gadsby	5,491,715	35,942	50,150	123,858	150,209	174,358	456,732	1,067,946	1,075,590	711,177	409,440	460,218	776,095
Gadsby CT	2,787,073	29,777	3,274	5,485	72,169	69,796	139,815	522,811	511,036	277,374	230,875	235,501	689,160
Hermiston	22,167,592	2,345,965	1,350,019	1,282,104	1,844,660	8,533	869,383	2,327,739	2,463,347	2,398,513	2,294,975	2,401,167	2,581,189
Lake Side 1	54,900,622	5,103,037	3,688,461	2,687,692	4,180,292	2,382,044	4,198,764	5,870,751	5,853,992	5,353,046	4,549,555	5,320,139	5,712,850
Lake Side 2	63,220,546	6,524,249	4,749,373	3,899,626	4,119,433	3,713,927	4,787,196	5,935,265	5,954,663	5,608,375	5,437,945	5,486,567	7,003,926
Naughton - Gas	20,317,381	2,531,859	2,433,992	1,963,691	593,083	1,074,098	1,226,797	1,988,607	1,826,395	1,191,663	1,313,676	1,403,712	2,769,808
Total Gas Fuel Burn	243,925,235	21,529,514	13,850,343	12,019,150	15,969,706	8,972,388	16,824,770	27,230,545	26,013,318	24,169,828	23,801,662	24,777,847	28,766,164
Gas Physical	(416,723)	(79,114)	(57,965)	(24,301)	(25,945)	(23,006)	(23,393)	(50,730)	(49,843)	(45,141)	(37,288)	-	-
Gas Swaps	(19,937,668)	(4,536,928)	(3,311,210)	(1,238,993)	(534,300)	(308,760)	(399,300)	(2,547,968)	(2,611,285)	(2,249,700)	18,135	(364,800)	(1,852,560)
Clay Basin Gas Storage	(588,564)	(334,019)	(307,763)	(216,982)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	2,850	(98,348)
Pipeline Reservation Fees	36,238,771	3,006,087	2,970,650	3,003,231	3,001,490	3,013,815	3,016,829	3,053,890	3,053,707	3,026,691	3,028,291	3,019,210	3,044,880
Total Gas Fuel Burn Expense	**259,221,051**	**19,585,541**	**13,144,055**	**13,542,105**	**18,463,195**	**11,706,680**	**19,471,149**	**27,737,980**	**26,458,139**	**24,953,920**	**26,863,043**	**27,435,107**	**29,860,136**
Other Generation													
Blundell	4,501,334	457,175	412,932	412,932	402,228	418,278	386,442	365,375	383,296	405,974	390,495	223,692	242,515
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	**4,501,334**	**457,175**	**412,932**	**412,932**	**402,228**	**418,278**	**386,442**	**365,375**	**383,296**	**405,974**	**390,495**	**223,692**	**242,515**
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Net Power Cost	**1,413,631,280**	**112,618,817**	**107,559,136**	**114,180,864**	**107,738,968**	**107,677,824**	**121,901,193**	**142,082,522**	**135,203,334**	**110,722,273**	**113,421,514**	**114,359,509**	**126,165,326**
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Net Power Cost/Net System Load	**23.78**	**21.61**	**23.57**	**24.01**	**24.12**	**23.06**	**24.46**	**24.60**	**24.44**	**23.20**	**24.41**	**23.97**	**23.83**