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Exh. RJM-1CTr
Docket UE-230172
Witness: Ramon J. Mitchell

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-230172

PACIFICORP

REDACTED DIRECT TESTIMONY OF RAMON J. MITCHELL

March 2023 (REVISED April 4, 2023, and REFILED April 19, 2023)

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ATTACHED EXHIBIT

Exhibit No. RJM-2—Washington-Allocated Net Power Costs

I. INTRODUCTION

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or 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 and I am testifying for PacifiCorp.

II. QUALIFICATIONS

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 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 filings.

Q. Have you testified in previous regulatory proceedings?

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

III. PURPOSE OF TESTIMONY

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

A. My testimony presents the forecast net power costs (NPC) for calendar year 2024 along with an explanation of the changes since the 2021 power cost only rate case

(PCORC).[1] I also provide an overview of the modeling changes that have been implemented to provide more accurate forecast NPC. Specifically, my testimony:

- Summarizes forecasted NPC for calendar year 2024 in this general rate case and explains the calculation of NPC using the Company's production cost model, Aurora;
- Explains the primary drivers behind the increase in NPC compared to the current baseline NPC approved by the Commission and incorporated into customer rates in the 2021 PCORC, that includes a discussion of increases in regional power market prices since the last case;
- Describes new and upcoming federal/state environmental compliance requirements and new operations changes since the 2021 PCORC that substantially impact NPC; and
- Describes modeling changes the Company has made to improve the NPC forecast accuracy since the 2021 PCORC.

Q. Do you present a specific NPC forecast for the second year of the multi-year rate plan?

A. No. The Company proposes to file a compliance filing by January 31, 2025, to refresh the NPC forecast for the second rate year effective March 1, 2025.

Q. Please provide a summary of your direct testimony.

A. My testimony supports an increase in Washington-allocated baseline NPC. I present and describe the drivers of the increased NPC, inclusive of changes in forward looking market prices, changes in federal and state environmental compliance

[1] *WUTC v. PacifiCorp,* Docket No. UE-210402.

requirements and changes in resource mix. Additionally, I explain how recent modeling improvements are incorporated into the NPC forecast. Finally, my testimony discusses hedging, summarizes the impacts of continued inclusion of the Jim Bridger plant and Colstrip unit 4 in the baseline NPC, presents updated coal costs, and presents a schedule for updates to NPC across this multi-year rate plan.

Q. How is the remainder of your testimony organized?

A. First, in Section IV, I present the updated NPC forecast and discuss the impacts of the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) on the NPC forecast. Then, in Section V, I provide an overview of the NPC forecast. This overview includes a high-level discussion of the NPC changes and the associated drivers since the last general rate case, docket UE-191024 (2020 Rate Case).

Second, Section VI follows with a more detailed discussion of the individual NPC components along with narrative explanations which touch on the impacts associated with new federal and state environmental compliance requirements and operations changes and Section VII includes a discussion on the reasonableness of the NPC forecast.

Third, in Section VIII, I discuss in detail new federal and state environmental compliance requirements and operations changes, along with the numeric impacts to the NPC forecast that each change represents. In Section IX, I present and discuss improvements to enhance modeling accuracy along with the numeric impacts to the NPC forecast that each improvement represents.

Fourth, in Section X, I present a brief discussion on hedging and refer to the 2022 Power Cost Adjustment Mechanism (PCAM), which will expand on this issue.

In Section XI, I discuss the impact of including the Jim Bridger plant and Colstrip unit 4 in the NPC forecast.

Finally, in Section XII, I present a brief summary on Company coal costs and the change in these costs between the last PCORC and this current filing, and in Section XIII, I provide a schedule for updates to NPC across this multi-year rate plan.

IV. FORECAST NPC

Q. Please provide an overview of NPC in the Company's filing.

A. The Company's Washington-allocated NPC is approximately $199.0 million. A report detailing the Washington-allocated NPC forecast is attached to my testimony as Exhibit No. RJM-2. Unless otherwise noted, references to NPC or various individual cost items throughout my testimony are stated in Washington-allocated amounts.

Q. How does the forecasted NPC in this proceeding compare to the NPC authorized in the Company's 2021 PCORC?

A. The forecasted Washington-allocated NPC in the current proceeding are approximately $53.8 million or 37 percent higher than the level authorized by the Commission in the 2021 PCORC. The drivers of this cost increase are described below in my testimony.

Q. Is the Company's general approach to forecasting NPC using Aurora the same in this case as in the 2021 PCORC?

A. Yes. As in the 2021 PCORC, the Company used Aurora from Energy Exemplar to forecast NPC.

Q. What modeling inputs were updated for this filing?

A. All inputs have been updated since the 2020 Rate Case, 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 the Company update the regulation reserve input for this filing?

A. Yes. Consistent with past NPC forecasts, the Company 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 that the Company used for its forecast NPC?

A. The forecast NPC use 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. An electronic version is included in the workpapers accompanying the Company's filing. That NPC report includes monthly data detailing major cost drivers.

Q. What is the WIJAM?

A. The Company recovers the costs of providing retail electric service to customers through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from the Company's integrated system, the collaborative Multi-State Process has been used to address allocation issues. This collaborative process has led to the development and adoption of a series of inter-jurisdictional cost allocation methods over time, with the most recent being the 2020 Protocol. Washington has traditionally used a different methodology than the Company's other jurisdictions, and this methodology was known as the West Control Area Inter-Jurisdictional Allocation Methodology (WCA). Along with the negotiations around the 2020 Protocol, the Company worked directly with Washington Staff, Public Counsel, and the Packaging Corporation of America to transition from the WCA to the WIJAM. In the order approving the 2020 Rate Case, the Commission adopted the WIJAM for cost allocations in Washington.[2]

Q. How does the WIJAM impact the modeling of forecast NPC?

A. The WIJAM changes the following items in the NPC forecast model:

- Inclusion of all power generation resources on the Company's system, with an adjustment to exclude the costs and benefits of emitting resources that are not electrically located in the PacifiCorp Balancing Authority Area West (PACW) and non-Washington QFs;
- Inclusion of system transmission on both a firm and non-firm basis;
- Inclusion of the new transmission incremental to the existing transmission system; and
- Inclusion of EIM benefits on a system basis.

V. DISCUSSION OF COST DRIVERS IN THE NPC FORECAST

Q. What are the proposed total-company NPC for calendar year 2024?

A. The proposed NPC for calendar year 2024 are $2.555 billion on a total-company basis and $199.0 million on a Washington-allocated basis.

Q. How is the total-company NPC forecast relevant to Washington?

A. Washington allocated NPC begins with the total-company NPC forecast, which is then allocated to Washington through the WIJAM. As noted above, NPC under the WIJAM are allocated using a spreadsheet method that reflects assets included in

[2] *WUTC v. Pac. Power & Light Co*., Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, and UE-180778, Final Order 09/07/12 at ¶112 (Dec. 14, 2020).

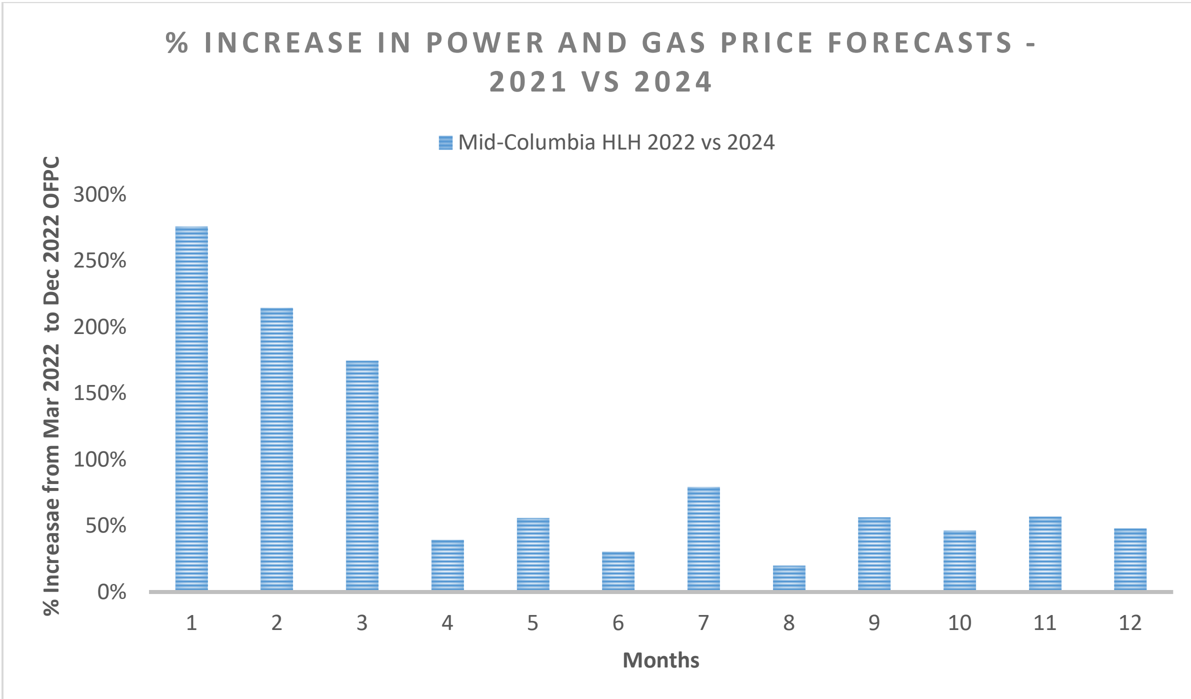
Washington rates. This method, based on relatively simple ratios and formulas, is driven first and primarily by the total-company forecast and then by the WIJAM specific allocations. Consequently, it is important to first understand the drivers of NPC at the total-company level and then explore the layered adjustments made under the WIJAM to arrive at the Washington-allocated NPC.

Q. Please generally describe the changes in total-company NPC compared to the 2021 PCORC.

A. The NPC forecast from the 2021 PCORC used a March 31, 2022 vintage OFPC to set the price expectations for calendar year 2022. Compared to calendar year 2024 price expectations from the December 31, 2022 vintage OFPC, average power market prices at Mid-Columbia increased by 80 percent as illustrated at the monthly granularity in Figure 1 below. As a result of this, the four substantive changes to the 2024 landscape, and modeling improvements as discussed in more detail below in my testimony, total-company NPC increased by $1.08 billion or 74 percent, from a 2021 PCORC under-forecast of $1.470 billion to this case's forecast of $2.555 billion.

In the context of the WIJAM however, Washington-allocated NPC increased by $53.8 million or 37 percent. This lesser percentage increase in the Washington-allocated NPC (37 percent) as compared to the total-company percentage increase (74 percent) is due to a reduction in Washington's market exposure (Shortfall), as discussed in more detail below in my testimony.

Figure 1



A. <u>Regional Power Market Price Increases</u>

Q. Why have regional power market prices increased?

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. Furthermore, expectations of continued abnormal weather conditions have placed a premium on power market prices in the regional marketplace.

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 and 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 energy price rise across the competitive regional power markets.

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[3] 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 load serving entities across the region have revised their expectations of load profiles upwards and this limits excess supply offered into the regional power markets.

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

These two weather-based drivers increase regional power market prices and both are additive to the increase caused by delays in renewable resource construction.

VI. NPC REPORT OVERVIEW

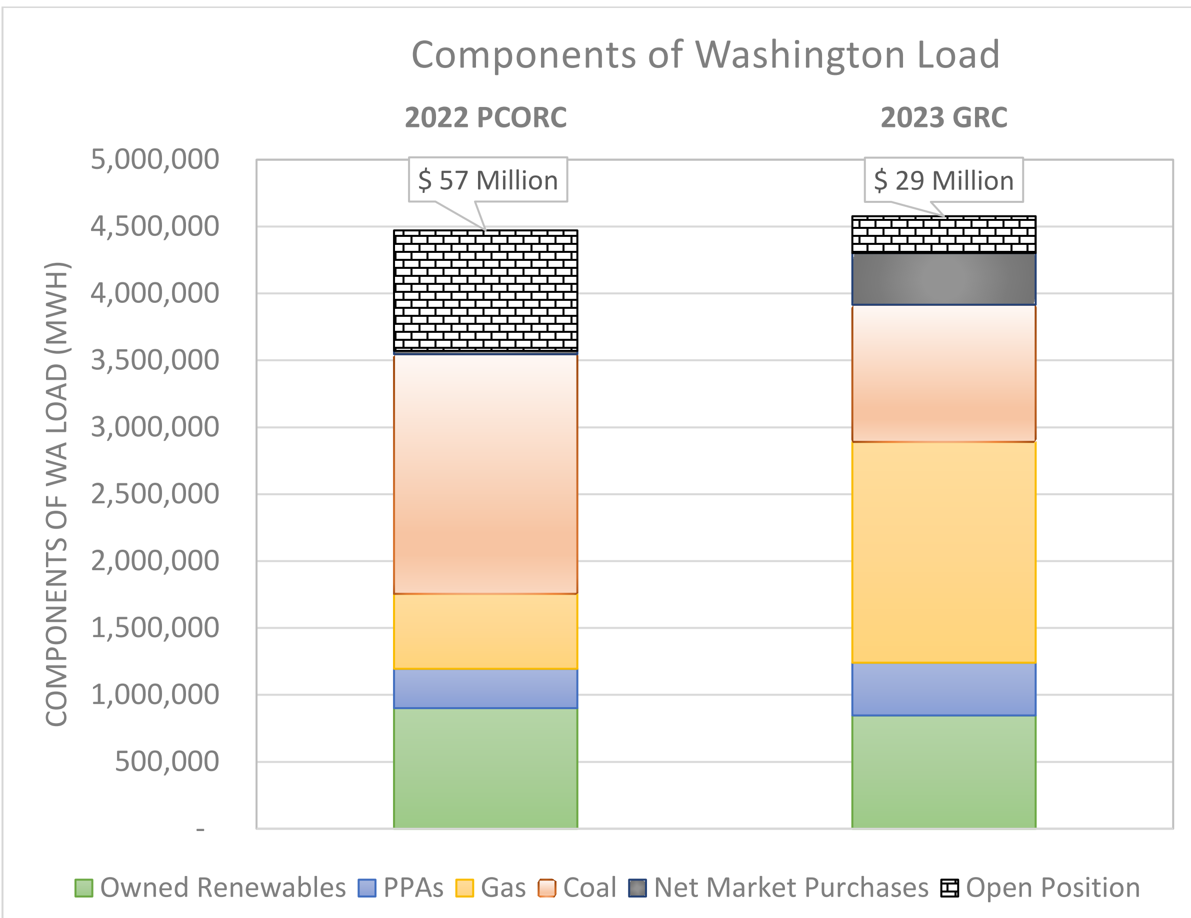
Q. Considering that Washington does not take a share of all power generation resources on PacifiCorp's system, please explain the spreadsheet-based WIJAM adjustments necessary to balance supply and demand.

A. Starting with the total-company NPC, Washington-allocated NPC are determined by comparing the Washington load to the generation and market activity (resources) that are allocated to Washington (*i.e.*, the resources that the WIJAM permits to be allocated to Washington, which is less than all the resources on the system). In this filing the Washington load exceeds Washington resources and this is shown as the Shortfall in Table 1 below. This Shortfall is calculated on a monthly basis and creates an open position, which is rebalanced in the WIJAM spreadsheet to arrive at the Washington-allocated NPC. For Shortfalls, the rebalancing is done by first reducing system balancing sales. If there are not sufficient system balancing sales to remove, system balancing purchases are then added in by the amount needed for Washington to maintain supply-demand balance. Any system balancing sales that are removed or system balancing purchases that are added in the rebalancing adjustment are done using the average price of either the system balancing sales or system balancing purchases. Table 1 below shows the WIJAM megawatt-hour (MWh) balancing adjustment in both the 2021 PCORC and the current filing while Figure 2 shows the open position before rebalancing.

Table 1

WIJAM Balancing (MWh)		
	2021 PCORC	2024 GRC
Shortfall	(895,041)	(274,926)
Decreased Sales	489,848	157,910
Increased Purchases	405,192	117,016
Net Open Position	-	-

Figure 2



Q. Please explain, by line item, the changes in Washington-allocated NPC compared to the 2021 PCORC.

A. Illustrated below in Table 2 for costs and Table 3 for energy are the line item changes in Washington-allocated amounts. Below, I expand on the individual line items.

Table 2

Net Power Cost Reconciliation ($)		
	($ millions)	$/MWh
WA 2021 PCORC Final Forecast	**145.2**	**32.47**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(19.56)	
Purchased Power Expense	35.10	
Coal Fuel Expense	(6.43)	
Natural Gas Fuel Expense	42.76	
Wheeling and Other Expense	1.93	
Total Increase to NPC	**53.80**	
WA 2024 GRC Initial Forecast	**199.0**	**43.47**

Table 3

Net Power Cost Reconciliation (MWh)		
	MWh	$/MWh
WA 2021 PCORC Final Forecast[1]	**4,446,352**	**32.47**
Change to Net System Load:		
Wholesale Sales Decrease	(190,462)	
Purchased Power Increase	7,221	
Coal Generation Increase	(755,423)	
Natural Gas Generation Increase	1,093,157	
Other Generation Increase	(49,524)	
Total Change to Net System Load	**104,969**	
WA 2024 GRC Initial Forecast	**4,551,321**	**43.47**

Q. Please explain the increase in purchased power expense.

A. At the total-company level, the purchased power expense increases in tandem with power market prices and increased purchased power volumes. The increase in purchased power volumes is 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 Cap and Invest program, 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.

In the WIJAM, relative to the 2021 PCORC, the energy Shortfall has decreased by 69 percent as illustrated in Table 1 above. Correspondingly, less purchased power volume is needed to close the net open position and this decrease in purchased power volume and the associated decrease in purchased power expense partially offsets the total increase in purchased power expense.

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

A. At the total-company level, 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.

However, in the WIJAM, coal expense is derived from only the Jim Bridger plant and Colstrip unit 4. As Jim Bridger Units 1 and 2 convert to gas, a large portion of the WIJAM coal expense decreases and this cost shifts to natural gas fuel expense.

This shift in expenses results in an overall decrease to coal expense from the perspective of the WIJAM, relative to the 2021 PCORC.

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

A. At the total-company level, with decreased net generation, wholesale sales volume also decreases, however, the increase in power market prices increases the total revenue of the remaining sales.

In the WIJAM, like purchased power, the decrease in the energy Shortfall results in less reductions to wholesale sales volumes required to close the net open position as compared to the 2021 PCORC. The net impact of this is an increase (less reductions to wholesale sales volume is equivalent to an increase) in wholesale sales volumes and a corresponding increase to wholesale sales revenue within the WIJAM, which layers on top of the total-company increase.

Wheeling expenses increase relative to the forecast in the 2021 PCORC based on increases in the historical wheeling expenses supporting 2022 actual purchased power volumes.

VII. NPC VALIDATION

Q. Is $2.555 billion a reasonable forecast for total-company NPC in 2024?

A. Yes. There are three layers to consider when assessing the total-company 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 total-company actual NPC and regional power market prices. First consider Table 4 below which shows the actual 2020 NPC, the actual 2021 NPC, the 2021 PCORC forecast of 2022 and the actual 2022 NPC, all in total-company dollars.

Table 4

NPC Type	Total Company NPC ($)
2020 Actual	1,511,314,189
2021 Actual	1,714,607,879
2022 Forecast (2021 PCORC)[4]	1,470,392,621
2022 Actual	2,040,736,242

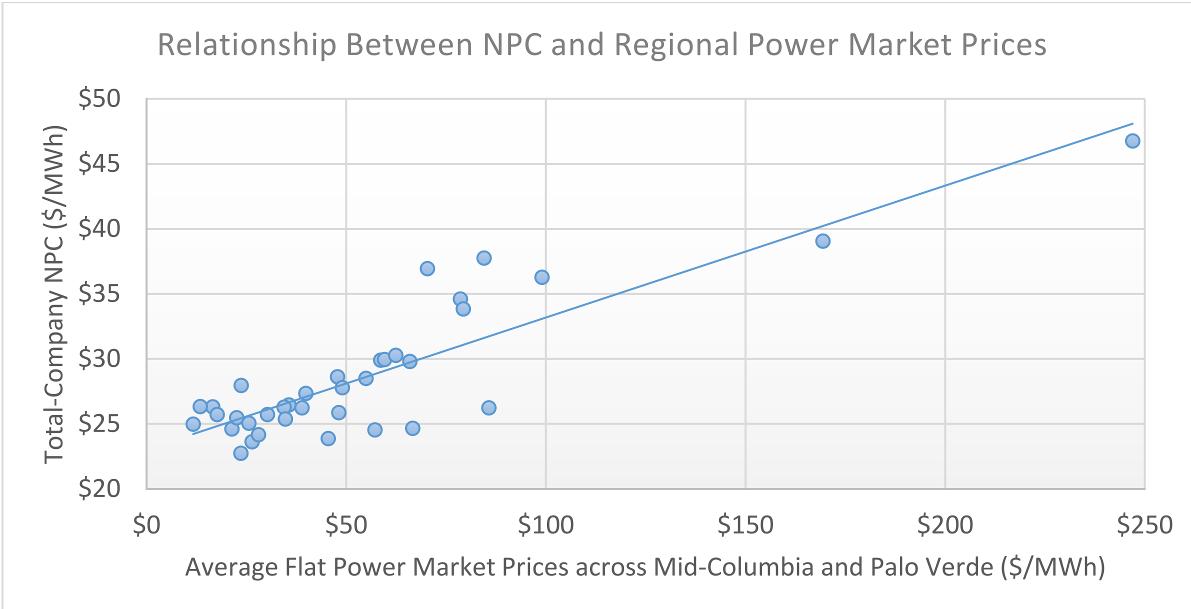
There are two items of note: (1) The 2021 PCORC NPC forecast of calendar year 2022 at $1.470 billion, total-company, was substantially under-forecast (*i.e.*, less than the actuals) relative to the actual calendar year 2022 NPC; and (2) within the actuals, there is a clear upward trend in NPC.

Q. Regarding the second layer, please elaborate on this upward trend in total-company 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 total-company NPC and regional power market prices as illustrated below in Figure 3.

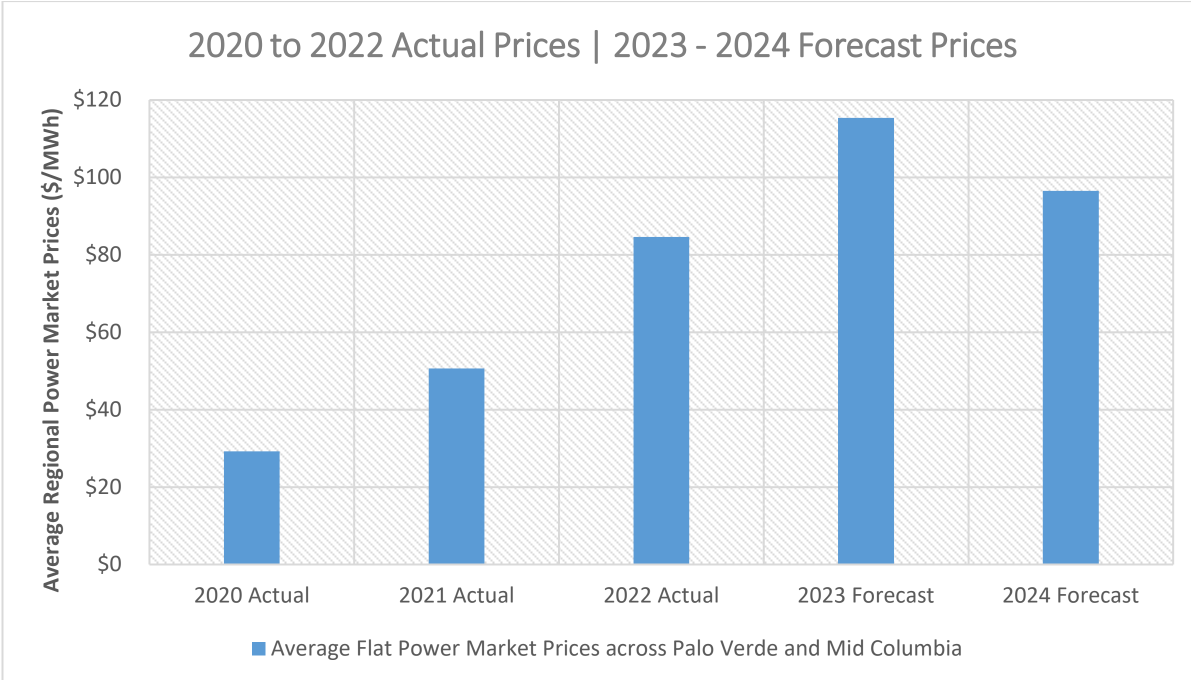
[4] 2021 PCORC total-company NPC forecast without production factor adjustment.

Figure 3



To establish a reference baseline of what a reasonable total-company 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 total-company NPC. This extrapolation suggests a total-company 2024 NPC of $2.201 billion. Figure 4 below illustrates year over year changes in actual and forecast regional power market prices that provide context for the total-company NPC increases in Table 4 and context for the extrapolation of total-company 2024 NPC at $2.201 billion.

Figure 4



Q. Regarding the third layer, please elaborate on some of the new and upcoming federal and state environmental compliance requirements and operational changes not captured in the total-company historical data or the trend.

A. Total-company 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 total-company 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) Washington's Cap and Invest program that subjects greenhouse gas (GHG) emissions to required purchases of GHG allowances (decreasing the dispatch of the Chehalis gas-fired plant located in Washington state); (3) the conversion of the Jim Bridger 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 total-company NPC are described in more detail, below in my testimony. In aggregate they increase total-company NPC by $353 million.

Q. How do these three layers demonstrate the reasonableness of the total-company 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 federal or state environmental compliance requirements or operations, $2.201 billion is a reasonable total-company NPC forecast for 2024. After layering on an additional $353 million (total-company) to account for the aforementioned upcoming federal and state environmental compliance requirements and operational changes, which are not reflected in the historical data, a reasonable benchmark for 2024 NPC becomes $2.554 billion (total-company) which is 0.06 percent below the proposed $2.555 total-company NPC. This difference of 0.06 percent results from the use of a relatively simple trend analysis as a reference for the total-company 2024 NPC (absent federal and state environmental compliance requirements or operations changes) as compared to the more detailed simulation within Aurora.

VIII. ENVIRONMENTAL REQUIREMENTS AND OPERATIONS CHANGES

Q. What federal and state environmental requirements 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 legislation in Washington, which drives GHG emissions reductions through required purchases of GHG allowances; (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 wind generation in Wyoming.[5]

A. <u>The Ozone Transport Rule</u>

Q. Please generally describe the OTR.

A. The EPA is in the process of establishing annual limits on the amount of NO_x that can be emitted by certain states including Wyoming and Utah. These NO_x limits apply during the ozone season, which spans May 1st to September 30th. They apply to Utah starting in 2023 and are assumed to apply to Wyoming starting in 2024. The rule is expected to be finalized soon, but there remains uncertainty regarding the implementation and the inclusion of Wyoming in 2024.

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.

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[5] 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 forecast period because they are already captured in the historical data that supports that reasonability analysis.

Q. There is uncertainty around the implementation of the OTR, how will you manage this uncertainty in the NPC forecast?

A. As noted above in my testimony, the Company is proposing to file a NPC update on February 16, 2024. At this point, there may be additional certainty around the implementation of the OTR and the NPC forecast will be updated.

Q. What is the impact to NPC of this environmental compliance requirement?

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

However, through the WIJAM, the Washington-allocated thermal generation increases due to the Chehalis plant and the Hermiston plant increasing generation to offset the net generation decrease observed across all Wyoming and Utah thermal units. This results in a net increase to Washington-allocated thermal generation, which lowers the WIJAM Shortfall and corresponding net open position. As a consequence, less market transactions are required to rebalance within the WIJAM, partially offset by large increases in total-company purchased power, and the Washington-allocated NPC *decrease* by $3.2 million as a result.

Assuming that only Utah is subject to the OTR in 2024, the impact of this adjustment at the total-company level is an increase to NPC of $17 million.

However, through the WIJAM, the Washington-allocated thermal generation increases due to the Chehalis plant, the Hermiston plant and the Jim Bridger plant increasing generation to offset the net generation decrease observed across Utah thermal units. This results in a net increase to Washington-allocated thermal generation, which lowers the WIJAM Shortfall and corresponding net open position. The majority of the OTR generation loss in Utah is covered by the aforementioned Washington-allocated thermal generation increases and only modest increases in total-company purchased power are needed to cover the remaining OTR generation loss. As a consequence, less market transactions are required to rebalance within the WIJAM, with minimal offset from total-company purchased power, and the Washington-allocated NPC *decrease* by $8.2 million as a result.

B. <u>The Washington Cap and Invest Program</u>

Q. Please generally describe the Washington Cap and Invest Program.

A. The Washington Cap and Invest program is a market-based program, which began in 2023, designed to reduce carbon pollution and achieve greenhouse gas limits and goals within Washington. The Chehalis gas-fired plant located in Washington is directly impacted by this program within the NPC simulation, since, for each unit of energy produced at the Chehalis plant there is an associated unit of GHG emissions and for each unit of GHG emissions there is an associated GHG allowance cost.

Q. How has the Washington Cap and Invest Program impacted Washington-allocated NPC?

A. There are two major impacts from the Cap and Invest program. The first impact is a reduction to the forecasted Chehalis generation (due to the cost of the emissions allowances required to operate the plant) and the associated NPC increase. This increases the dispatch cost of Chehalis, which means that the output of the Chehalis plant will decrease when compared to other generation sources with a lower dispatch cost. The second impact is the removal of the cost of the emissions allowances in the WIJAM to account for the no-cost allowances issued to the Company for Washington load service and the associated NPC decrease.

Q. What is the GHG allowance cost applied to the Chehalis plant for calendar year 2024?

A. The GHG allowance cost is currently estimated at 24.75 dollars per MWh ($/MWh) for calendar year 2024 based on an independent analysis commissioned by Washington's Department of Ecology.[6] The program commences at the beginning of 2023, the first auction will take place in the second half of February 2023 and results will be published in March 2023. The NPC forecast will be updated with refreshed prices in the NPC update.

Q. How is Washington-allocated NPC impacted by the cost of emissions allowances in the Washington Cap and Invest program?

A. As previously mentioned, the emissions allowance cost for Chehalis is currently estimated at $24.75/MWh for calendar year 2024 based on an independent analysis commissioned by Washington's department of Ecology through Vivid Economics. After application of the estimated emissions allowance cost to the Chehalis plant, Washington-allocated NPC increases by $16.8 million. Then, after removing the emissions allowance cost in the WIJAM, Washington-allocated NPC decreases by $15.4 million. The delta between the increase and the decrease ($1.3 million) is primarily attributable to the increase in the WIJAM Shortfall due to the reduction in Chehalis generation.

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[6] WASHINGTON DEPARTMENT OF ECOLOGY, *Final Regulatory Analysis* at pg. 129 (Sept. 2022), *available at* https://apps.ecology.wa.gov/publications/documents/2202047.pdf.

Q. If Washington provides no-cost allowances to account for Washington load service, why is the Cap and Invest program still resulting in increased NPC?

A. As previously mentioned, in the WIJAM spreadsheet allocation method there is a net open position that results from insufficient energy allocated to serve Washington load. This net open position is closed with modeled energy at average market prices and the resulting cost increases Washington-allocated NPC. Since the Cap and Invest program decreases the energy output (generation) at the Chehalis plant, the WIJAM's net open position becomes larger. Therefore, the resulting cost to close this net open position becomes correspondingly greater.

C. Jim Bridger's Gas Conversion

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 Wyoming Public Service Commission.[7]

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.[8] Past December 31, 2023, gas conversion was identified as a more economically viable option in the long-term analysis of the

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[7] *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).
[8] 40 C.F.R. §52.2636(d)(1).

integrated resource planning process partially driven by a need for the Company to retain as much upward-dispatchable capacity as possible.

Q. What is the Washington-allocated 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 $4.5 million. This increase is driven by the fact that natural gas fuel is on average 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 $8.0 million increase to NPC. This increase is driven by increased market purchases to cover the generation loss.

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.

Q. Why is the Washington-allocated impact to NPC due to the gas conversion outage period of greater magnitude than the gas conversion itself?

A. Through the WIJAM, the Washington-allocated thermal generation decreases substantially because of the combined outage at Jim Bridger Units 1 and 2. This increases the WIJAM Shortfall and corresponding net open position. Therefore, more market transactions are required to re-balance within the WIJAM as compared to a scenario in which the outage didn't take place at all.

D. Hydroelectric Generation Reduction

Q. By how much has hydroelectric generation decreased between the 2021 PCORC and this current filing?

A. The forecast for calendar year 2024 hydroelectric generation has decreased by approximately 642,000 MWh (18 percent) as compared to the calendar year 2022 forecast from the 2021 PCORC.

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[9] and is picked up in the normalized hydroelectric generation. Additionally, the pending removal of the four Company-operated hydroelectric projects[10] 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. The removal of these projects are discussed in further detail in the testimony of Company witness Sherona L. Cheung.

Q. What is the impact to Washington-allocated NPC of these hydroelectric projects' deconstruction?

A. The impact of this adjustment is an increase of $3.6 million. This increase is driven by increased market purchases to cover the generation reduction.

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

E. 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 planning to build 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.

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, including renewable energy. Specifically, it will allow for the release of "trapped energy" from wind resources in Wyoming. The concept of trapped energy is discussed in more detail, below in my testimony.

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

A. Under the current assumption that the line comes into service in October of 2024, the impact of this adjustment is a *decrease* of $3.6 million, primarily driven by increased wind generation.

IX. MODELING IMPROVEMENTS TO THE NPC FORECAST

Q. Why are modeling improvements necessary?

A. Modeling improvements are needed to align the NPC forecasting methodology to operational realities for the purpose of increasing accuracy of the NPC forecast. In the 2021 PCORC compliance filing submitted on April 15, 2022, based on the March 2022 OFPC, the Company forecasted total-company NPC for calendar year 2022 at

$1.470 billion (absent production factor adjustment). Actual NPC for calendar year 2022 was recorded at $2.041 billion, an under-forecast of $570 million relative to the PCORC forecast.

Q. What modeling improvements have been implemented since the 2021 PCORC?

A. The following modeling improvements have been implemented since the 2021 PCORC:

- 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 derates to unit capacity during the summer months.

A. 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-hubindexed 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 at the total-company level is an increase of $10.7 million to NPC. The primary driver for this change is the captured effect of intra-month market volatility.

However, a consequence of this adjustment at the total-company level is that the average price ($/MWH) of wholesale sales decreases by a modest amount, which lowers the cost of re-balancing the shortfall in the WIJAM to close the net open position. Consequently, in the WIJAM the impact of this adjustment *decreases* Washington-allocated NPC by $0.18 million as a result.

B. <u>Trapped Energy</u>

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 the old Generation and Regulation Initiative Decision Tools (GRID) model?

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 cost (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 a Washington-allocated increase to NPC of $3.9 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.

C. <u>Thermal Attributes</u>

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 a Washington-allocated increase to NPC of $1.7 million. This increase is driven by increased market purchases.

X. HEDGING

Q. Please provide a brief overview of how the Company hedges for its system.

A. Typically, the Company layers in hedges over time and the most actively managed hedging period is the 12-month forward looking period at any given point in time. For perspective, and as an example, the hedges included in this filing were as of December 31, 2022. This means that the entirety of this filing's forecast period (beginning January 1, 2024) is outside of this actively managed, 12-month forward looking period. However, the hedges for the forecast period will increase over time in keeping with the Company's hedging policy.

Q. How does the Company hedge for Washington customers?

A. The Company hedges its entire system holistically. There is no separate hedge book for transactions allocated to Washington specifically. In this filing, Washington's allocation of generation resources remains short against Washington load and, consequently, approximately 6 percent of Washington load has to be satisfied using modeled market interactions through the WIJAM. For context, consider that in the 2021 PCORC, approximately 20 percent of Washington load had to be satisfied using modeled market interactions, which shows a substantial filing-over-filing reduction to Washington's market exposure.

Q. Will the Company address the prudence of applying the Company's risk management and hedging policies to the load and resource mix of Washington customers in the 2022 PCAM?

A. Yes. Per the Commission's order from the 2021 PCORC, this issue will be discussed in the 2022 PCAM.

XI. JIM BRIDGER AND COLSTRIP IN RATES

Q. Why has the Company included the NPC benefits of Jim Bridger and Colstrip unit 4 in this case's NPC forecast?

A. As described in the testimony of Company witness Matthew D. McVee, the Company has the option under the WIJAM of keeping Jim Bridger and Colstrip Unit 4 in Washington rates until the end of 2025. Because of the NPC impacts of removing these resources from rates, the Company has elected to keep those units in rates until the end of 2025.

Within this context, the Company assessed the NPC impacts of a scenario in which Jim Bridger Units 3 and 4 (the coal portions of Jim Bridger) and Colstrip Unit 4 (Colstrip) were excluded from the NPC forecast as compared to a scenario in which the aforementioned resources were included. This analysis demonstrates substantial benefits to Washington customers from the inclusion of these resources in the NPC forecast.

An additional scenario examines the impacts of excluding Jim Bridger Units 1 and 2 (the gas converted portion of Jim Bridger). This analysis also demonstrates substantial benefits to Washington customers.

Q. What are the NPC impacts from excluding Jim Bridger unit 3 and unit 4 along with Colstrip unit 4 from the NPC forecast?

A. Washington-allocated NPC increased by $72 million (36 percent) from $199 million to $271 million with the exclusion of Jim Bridger Units 3 and 4, and Colstrip Unit 4 from the NPC forecast due to a substantial increase (1.03 million MWh or 373 percent) in the WIJAM Shortfall and the associated costs of re-balancing to close the net open position.

Q. What are the NPC impacts from excluding Jim Bridger Units 1 and 2 from the NPC forecast?

A. Washington-allocated NPC increased by $50 million (25 percent) from $199 million to $249 million with the exclusion of Jim Bridger Units 1 and 2 from the NPC forecast due to a substantial increase (0.893 million MWh or 225 percent) in the WIJAM Shortfall and the associated costs of re-balancing to close the net open position. This NPC impact is separate from the gas conversion outage impact, which shows an $8 million cost that will be incurred from [redacted], due to these two units not being in the NPC Forecast.

Q. How are the capital costs associated with the inclusion of Jim Bridger and Colstrip Unit 4 in Washington rates treated?

A. Company witness Cheung provides detail on this treatment in their testimony.

XII. FORECAST COAL COSTS

Q. Has forecast coal expense in calendar year 2024 decreased from the amount in the 2021 PCORC?

A. Yes. Forecast coal fuel expense decreased by $6.43 million on a Washington-allocated basis, from $45.7[11] million in the 2021 PCORC to $39.3 million in calendar year 2024.

Q. Please explain why coal fuel expense decreased in calendar year 2024.

A. From the perspective of Washington rates there are five coal-fired units: Jim Bridger Units 1-4, and Colstrip Unit 4. Within this context, the decrease in coal fuel expense is primarily driven by the conversion of Jim Bridger Units 1 and 2 from coal-fired units to gas-fired units, which shifts a large portion of the expense from coal fuel to natural gas fuel.

Q. Please quantify the reduced coal consumption amount in calendar year 2024.

A. On a Washington-allocated basis, the calendar year 2024 NPC forecasts consumption of 11.2 million British Thermal Units (MMBtu), which is 7.7million MMBtu less than the 2021 PCORC. This is a 41 percent decrease.

Q. Is the impact of the reduced coal consumption similar at Jim Bridger and Colstrip Unit 4?

A. No. As a result of the gas conversion of Jim Bridger Units 1 and 2, on a Washington-allocated basis, the Jim Bridger plant is projected to consume [redacted] million MMBtus of coal in calendar year 2024, which is [redacted] million MMBtus or [redacted] percent [redacted] than in the 2021 PCORC. On a Washington-allocated basis, Colstrip Unit 4 is projected to

[11] Adjusted by the 2024 PCORC production factor.

consume approximately [redacted] million MMBtus in calendar year 2024, which is approximately [redacted] MMBtus or [redacted] percent [redacted] than forecast in the 2021 PCORC.

A. <u>Jim Bridger Coal Costs</u>

Q. Please explain the coal supply arrangements for Jim Bridger.

A. Like the 2021 PCORC, Jim Bridger is expected to be supplied by a combination of coal supplies from the Bridger Coal Company (BCC) and the Black Butte mine in calendar year 2024.

Q. Can you please quantify the coal cost decrease at Jim Bridger?

A. Yes. Jim Bridger coal costs decrease by $6.7 million on a Washington-allocated basis due to the gas conversion of Units 1 and 2.

Q. What are the coal cost changes at BCC?

A. BCC coal costs [redacted] from [redacted] per ton in the 2021 PCORC to [redacted] per ton in calendar year 2024.

Q. Please identify the drivers of BCC coal cost per ton change.

A. The primary driver of the cost change from BCC is due to the reduction in coal forecast to be delivered from BCC, which in turn is attributable to the OTR generation restrictions. For context, it is important to note that on a $/MMBtu basis, BCC coal is, on average, cheaper than natural gas sourced from the Opal hub and on a $/MWh basis, BCC coal burned at Jim Bridger is, on average, cheaper than average market purchases.

Q. Did the Black Butte coal price increase in calendar year 2024 as compared to the 2021 PCORC?

A. [redacted]. The Black Butte coal price in calendar year 2024 is based on an estimated amount of [redacted] per ton for 2024, which is [redacted] per ton [redacted] than the [redacted] per ton assumed in the 2021 PCORC.

B. <u>Colstrip Unit 4 Coal Costs</u>

Q. Did coal prices increase at Colstrip Unit 4 in calendar year 2024 as compared to the 2021 PCORC?

A. [redacted]. Delivered coal prices [redacted] per ton, from [redacted] per ton in the 2021 PCORC to [redacted] per ton in calendar year 2024.

Q. Please explain the coal supply arrangements for Colstrip Unit 4.

A. Colstrip Unit 4 is supplied by coal delivered from the Rosebud Mine owned by Westmoreland Rosebud Mining, LLC.

XIII. NPC UPDATES ACROSS THIS MULTI-YEAR PLAN

Q. Please explain why the Company is proposing three separate NPC updates that will occur through the course of this multi-year rate plan.

A. The Company is proposing three separate updates to ensure that (1) customers get the most accurate NPC forecast that is available in rates, (2) the costs and benefits of new investments in renewable generation are incorporated into rates for customers, and (3) compliance with the Clean Energy Transformation Act.

Q. Can you provide additional detail on the NPC update schedule?

A. Yes, please refer to Table 5 below, which details the schedule for the three NPC updates proposed by the Company.

Table 5

Compliance Filing Date	**Rate Effective Date**	**Official Forward Price Curve Date**	**Purpose of NPC Update**
February 16, 2024	March 1, 2024	December 2023	Provide most accurate NPC for first rate effective date
January 31, 2025	March 1, 2025	December 2024	Incorporate new resources into the forecast to match costs and benefits for second rate year
October 31, 2025	January 1, 2026	September 2025	Remove Jim Bridger and Colstrip coal facilities from NPC forecast to comply with CETA

Q. Please explain what will be updated in each compliance filing.

A. These updates will be the same as the update that occurred in the compliance filing to the Company's 2021 PCORC. These updates will be calculated in the same manner as the baseline that was used to derive the revenue requirement for this case. These updates will be based on the most recent OFPC available and will also reflect the Company's electric and gas hedging and contract positions as of the latest OFPC date. This specifically includes:

- Wholesale electric sale and purchase contracts that are for long-term firm sales and purchases (including long-term power purchase agreements),
- Short-term firm sales and purchases,
- Natural gas sales and purchase contracts.

Q. Please describe the steps, in detail, that are necessary to complete each update.

A. First, forward prices for natural gas and electricity will be updated in Aurora itself. In addition, hedge positions for power and gas will be updated based on the most recent month-end hedge positions available, and any mark-to-market values will be updated to reflect the use of the same OFPC that was described in the first step. Any new power purchase agreements and Qualifying Facility contracts will be included in the model, and any required updates to contracts that were previously included will be made. Finally, Energy Imbalance Market (EIM) transfer and greenhouse gas (GHG) benefits will be reforecast, also based on the same OFPC, to synchronize the NPC inputs for the most accurate output.

Q. How is the Company able to complete an update during the rate year in which rates are being forecast?

A. The Company proposes to use the average of settled daily prices in place of broker quotes for the first three months of the forecast period, with other inputs to the model formulated in a manner consistent with the study supporting the direct filing in this case. This will allow the update to still reflect a normalized forecast, but also solves the problem of not having broker support for prices covering historical months. This same process was also used in the Company's 2021 PCORC.

Q. Why is it good policy to conduct a power cost update?

A. NPC is recovered by setting a forecast baseline in a general rate case or power-cost only rate case and then using the PCAM to account for variations in actual NPC. Using the latest and most accurate information to set the power cost baseline (which is a forecast) makes sense, because it allows for the costs set in the baseline to be more accurate and reflective of the most up-to-date market information.

Q. Does the compliance filing as proposed allow enough time for review of the power cost update?

A. Yes, this update process allows for the same amount of time between the compliance filing and the rate effective date as was approved in the Company's last PCORC.

Q. Are there any differences in the scope and timing of these compliance filing updates when compared to the update that was adopted by the Commission in the last PCORC?

A. No.

XIV. CONCLUSION

Q. What actions are you recommending the Commission take?

A. I recommend that the Commission approve the proposed modeling improvements as outlined in my testimony, adopt the proposed NPC baseline of $199.0 million on a Washington-allocated basis, and approve the NPC update process that is described in my testimony.

Q. Does this conclude your direct testimony?

A. Yes.

Exh. RJM-2
Docket UE-230172
Witness: Ramon J. Mitchell

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-230172

PACIFICORP

EXHIBIT OF RAMON J. MITCHELL

Washington-Allocated Net Power Costs

March 2023 (REFILED April 19, 2023)

WAGRC24

	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	$ 28,197	$ 2,096	$ 1,875	$ 2,220	$ 1,295	$ 1,623	$ 1,786	$ 4,459	$ 4,392	$ 3,050	$ 1,934	$ 1,535	$ 1,933
PSCo_Sale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Long Term Firm Sales	$ 28,197	$ 2,096	$ 1,875	$ 2,220	$ 1,295	$ 1,623	$ 1,786	$ 4,459	$ 4,392	$ 3,050	$ 1,934	$ 1,535	$ 1,933
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	$ 8,803,022	$ 931,076	$ 608,701	$ 447,177	$ 290,757	$ 337,996	$ 503,789	$ 613,220	$ 740,779	$ 1,179,101	$ 1,041,170	$ 991,042	$ 1,118,213
Four Corners	$ 6,543,108	$ 1,056,396	$ 470,432	$ 501,300	$ 344,525	$ 207,462	$ 332,311	$ 384,966	$ 280,869	$ 682,783	$ 558,245	$ 756,051	$ 967,769
Mead	$ 101,798	$ 14,043	$ 3,648	$ (429)	$ 14,891	$ 1,076	$ 2,729	$ 10,070	$ 24,175	$ 31,798	$ 12,952	$ 1,956	$ (15,112)
Mid Columbia	$ 17,101,195	$ 2,369,926	$ 1,326,144	$ 981,119	$ 790,403	$ 615,040	$ 363,969	$ 2,210,218	$ 2,527,543	$ 1,767,528	$ 1,402,488	$ 1,152,596	$ 1,594,221
Mona	$ 1,654,370	$ 243,228	$ 235,697	$ 95,061	$ 24,489	$ 8,875	$ 124,893	$ 66,609	$ 122,241	$ 414,136	$ 100,432	$ 81,161	$ 137,547
NOB	$ 1,376,513	$ 131,742	$ 113,121	$ 113,656	$ 42,179	$ 32,150	$ 98,877	$ 146,686	$ 213,332	$ 191,773	$ 111,818	$ 109,600	$ 71,579
Palo Verde	$ 449,155	$ 55,841	$ 32,167	$ 26,859	$ 6,416	$ 3,899	$ 41,143	$ 44,007	$ 102,910	$ 28,544	$ 33,526	$ 38,060	$ 35,783
Trapped Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total System Balancing Sales	$ 20,295,959	$ -	$ -	$ -	$ 653,624	$ 740,014	$ 1,467,711	$ 3,475,776	$ 4,011,850	$ 3,581,864	$ 3,260,629	$ 3,104,491	$ -
Total Special Sales For Resale	$ 20,324,156	$ 2,096	$ 1,875	$ 2,220	$ 654,918	$ 741,637	$ 1,469,497	$ 3,480,235	$ 4,016,242	$ 3,584,915	$ 3,262,564	$ 3,106,025	$ 1,933

Purchased Power & Net Interchange													
Long Term Firm Purchases													
Appaloosa 1A Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Appaloosa 1B Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar UoU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar IHC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind	$ 938,684	$ 107,622	$ 90,691	$ 82,361	$ 81,067	$ 66,290	$ 59,353	$ 59,265	$ 46,755	$ 66,024	$ 87,012	$ 85,241	$ 107,003
Cedar Springs Wind III	$ 713,272	$ 81,806	$ 68,902	$ 62,573	$ 61,605	$ 50,368	$ 45,108	$ 45,030	$ 35,522	$ 50,173	$ 66,118	$ 64,774	$ 81,294
Cedar Springs Wind IV	$ 3,484	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,484
Combine Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cove Mountain Solar	$ 305,176	$ 14,610	$ 15,898	$ 26,756	$ 29,128	$ 33,526	$ 36,056	$ 34,975	$ 33,094	$ 28,379	$ 22,845	$ 16,414	$ 13,495
Cove Mountain Solar II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deseret Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eagle Mountain - UAMPS/UMPA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 20yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 25yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gemstate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Graphite Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hermiston Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Horseshoe Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hunter Solar	$ 561,006	$ 29,468	$ 34,600	$ 50,894	$ 53,117	$ 60,569	$ 62,677	$ 59,585	$ 56,012	$ 52,227	$ 44,570	$ 31,611	$ 25,675
Hurricane Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Buythru	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Reserves	$ 260,439	$ 21,757	$ 21,117	$ 21,757	$ 21,757	$ 21,757	$ 21,757	$ 21,757	$ 21,757	$ 21,757	$ 21,757	$ 21,757	$ 21,757
Milican Solar	$ 231,296	$ 7,605	$ 12,020	$ 17,781	$ 22,381	$ 26,564	$ 28,915	$ 32,562	$ 28,773	$ 23,156	$ 15,162	$ 9,711	$ 6,664
Milford Solar	$ 553,529	$ 27,976	$ 33,367	$ 47,521	$ 52,858	$ 62,143	$ 65,520	$ 58,348	$ 56,171	$ 52,397	$ 42,258	$ 30,744	$ 24,225
Nucor	$ 568,873	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406	$ 47,406
Old Mill Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monsanto Reserves	$ 1,643,633	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969	$ 136,969
Pavant III Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PGE Cove	$ 10,663	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889	$ 889
Prineville Solar	$ 154,101	$ 5,221	$ 8,251	$ 11,814	$ 14,870	$ 17,649	$ 19,210	$ 21,633	$ 19,116	$ 15,384	$ 10,073	$ 6,452	$ 4,427
Rocket Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sigurd Solar	$ 470,784	$ 24,577	$ 28,420	$ 40,471	$ 44,187	$ 50,786	$ 55,818	$ 51,895	$ 47,572	$ 44,414	$ 36,040	$ 25,328	$ 21,276
Skysol Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Small Purchases east	$ 1,088	$ 89	$ 92	$ 89	$ 89	$ 94	$ 92	$ 93	$ 92	$ 88	$ 88	$ 92	$ 90
Small Purchases west	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Soda Lake Geothermal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Buttes Wind	$ 1,664,239	$ 224,400	$ 154,360	$ 171,742	$ 129,953	$ 114,798	$ 96,954	$ 64,782	$ 76,362	$ 95,301	$ 139,542	$ 189,188	$ 206,855
Top of the World Wind	$ 3,086,963	$ 261,464	$ 244,595	$ 261,464	$ 253,030	$ 261,464	$ 253,030	$ 261,464	$ 261,464	$ 253,030	$ 261,464	$ 253,030	$ 261,464
Wolverine Creek Wind	$ 856,554	$ 63,329	$ 75,212	$ 94,304	$ 86,772	$ 65,523	$ 70,390	$ 55,758	$ 53,036	$ 62,637	$ 68,951	$ 80,159	$ 80,480
Glen Canyon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rush Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anticline Wind	$ 1,488	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,488
Boswell Springs Wind	$ 4,556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,556
Two River Wind LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Creek	$ 783,902	$ -	$ -	$ -	$ -	$ -	$ 1,573	$ 109,885	$ 86,940	$ 104,518	$ 174,059	$ 170,148	$ 136,779
UT Schedule Adjustment	$ 650,922	$ 46,858	$ 46,642	$ 46,583	$ 46,601	$ 46,858	$ 69,754	$ 69,184	$ 69,184	$ 69,074	$ 46,720	$ 46,743	$ 46,720
Long Term Firm Purchases Total	$ 13,464,649	$ 1,102,046	$ 1,019,432	$ 1,121,374	$ 1,082,680	$ 1,063,653	$ 1,071,471	$ 1,131,482	$ 1,077,113	$ 1,123,823	$ 1,221,922	$ 1,216,657	$ 1,232,996

Qualifying Facilities													
QF California	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
QF Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
QF Oregon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
QF Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Biomass One QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chopin Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCFP QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Enterprise Solar I QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Escalante Solar I QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Escalante Solar II QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Escalante Solar III QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Five Pine Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Granite Mountain East Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Granite Mountain West Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Iron Springs Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Latigo Wind Park QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mountain Wind 1 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mountain Wind 2 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
North Point Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oregon Wind Farm QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchard Wind 1 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchard Wind 2 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchard Wind 3 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchard Wind 4 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pavant II Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pioneer Wind Park I QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power County North Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Power County South Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Roseburg Dillard QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sage I Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sage II Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sage III Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spanish Fork Wind 2 QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sunnyside QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sweetwater Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tesoro QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Threemile Canyon Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Peaks Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah Pavant Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah Red Hills Solar QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Qualifying Facilities Total	$ 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
Mid-Columbia Contracts													
Douglas - Wells	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grant Reasonable	$ (732,249)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)	$ (61,021)
Grant Meaningful Priority	$ 5,066,719	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227	$ 422,227
Grant Surplus	$ 195,370	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281	$ 16,281
Grant - Priest Rapids	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid-Columbia Contracts Total	$ 4,529,840	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487	$ 377,487
Total Long Term Firm Purchases	$ 18,589,931	$ 1,484,644	$ 1,406,946	$ 1,515,356	$ 1,491,465	$ 1,503,114	$ 1,567,711	$ 1,642,343	$ 1,571,775	$ 1,576,626	$ 1,615,072	$ 1,600,024	$ 1,614,856
Storage & Exchange													
Rush lake_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Umpqua Storage Placeholder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cowlitz Swift	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCo Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCO FC III	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redding Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SCL State Line	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage & Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Short Term Firm Purchases													
Borah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COB	$ 1,615,172	$ 233,380	$ 224,404	$ 233,380	$ -	$ -	$ -	$ 312,003	$ 324,003	$ 288,003	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ 456,352	$ 154,093	$ 148,166	$ 154,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Purchases	$ 2,071,525	$ 387,473	$ 372,570	$ 387,473	$ -	$ -	$ -	$ 312,003	$ 324,003	$ 288,003	$ -	$ -	$ -
System Balancing Purchases													
COB	$ 5,091,828	$ 284,601	$ 600,445	$ 633,222	$ 70,660	$ 169,339	$ 311,274	$ 1,122,462	$ 916,693	$ 417,198	$ 225,866	$ 144,203	$ 195,865
Four Corners	$ 4,807,488	$ 431,185	$ 287,457	$ 246,409	$ 206,008	$ 211,778	$ 295,842	$ 900,617	$ 477,522	$ 673,337	$ 385,408	$ 315,925	$ 375,999
Mead	$ 213,487	$ 4,056	$ -	$ 6,164	$ 7,135	$ -	$ 28,571	$ 2,436	$ 52,333	$ 30,820	$ 1,080	$ 6,629	$ 74,264
Mid Columbia	$ 51,991,762	$ 5,155,993	$ 2,848,715	$ 2,803,853	$ 2,642,830	$ 3,385,076	$ 3,464,564	$ 8,129,741	$ 8,442,816	$ 4,529,891	$ 2,999,597	$ 2,553,898	$ 5,034,790
Mona	$ 1,498,766	$ 122,122	$ 192,252	$ 76,432	$ 26,062	$ 18,103	$ 164,876	$ 27,615	$ 106,259	$ 362,205	$ 126,655	$ 106,973	$ 169,212
NOB	$ 10,851,021	$ 1,095,155	$ 960,936	$ 759,418	$ 168,307	$ 650,868	$ 589,798	$ 1,499,675	$ 1,420,699	$ 1,187,982	$ 677,575	$ 796,295	$ 1,044,314
Palo Verde	$ 1,654,901	$ 210,507	$ 97,648	$ 133,711	$ 54,726	$ 104,277	$ 121,975	$ 216,652	$ 273,570	$ 8,261	$ 155,145	$ 140,339	$ 138,091
EIM Imports/Exports	$ (10,535,276)	$ (1,194,103)	$ (903,514)	$ (796,658)	$ (594,137)	$ (620,053)	$ (646,641)	$ (1,168,508)	$ (1,215,970)	$ (1,017,497)	$ (695,021)	$ (737,059)	$ (946,115)
Emergency Purchases	$ 185,790	$ -	$ -	$ 1,616	$ -	$ 50,148	$ 3,492	$ 92,565	$ 23,480	$ 50	$ 14,438	$ -	$ -
Total System Balancing Purchases	$ 78,932,940	$ 15,226,476	$ 10,514,085	$ 6,388,764	$ 2,581,591	$ 3,969,536	$ 4,052,184	$ 8,823,642	$ 8,734,526	$ 6,192,247	$ 1,110,904	$ 3,327,203	$ 8,011,781
Total Purchased Power & Net Interchange	$ 99,594,396	$ 17,098,592	$ 12,293,601	$ 8,291,594	$ 4,073,055	$ 5,472,650	$ 5,619,895	$ 10,777,988	$ 10,630,305	$ 8,056,876	$ 2,725,976	$ 4,927,227	$ 9,626,637
Wheeling & U. of F. Expense													
Firm Wheeling	$ 13,145,245	$ 996,559	$ 1,040,484	$ 1,103,035	$ 1,119,006	$ 1,061,668	$ 1,130,277	$ 1,345,301	$ 1,208,371	$ 1,170,712	$ 1,012,555	$ 919,894	$ 1,037,383
C&T EIM Admin fee	$ 208,271	$ 16,031	$ 14,685	$ 17,567	$ 16,787	$ 17,644	$ 17,757	$ 17,934	$ 19,520	$ 17,382	$ 17,242	$ 17,061	$ 18,661
ST Firm & Non-Firm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Wheeling & U. of F. Expense	$ 13,353,516	$ 1,012,589	$ 1,055,170	$ 1,120,603	$ 1,135,793	$ 1,079,311	$ 1,148,034	$ 1,363,235	$ 1,227,891	$ 1,188,094	$ 1,029,797	$ 936,955	$ 1,056,044
Coal Fuel Burn Expense													
Colstrip	$ 2,291,937	$ 149,656	$ 176,582	$ 209,706	$ 196,650	$ 224,553	$ 211,078	$ 229,567	$ 234,025	$ 217,499	$ 110,695	$ 132,934	$ 198,990
Craig	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dave Johnston	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hayden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hunter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Huntington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jim Bridger	$ 36,996,494	$ 3,547,012	$ 3,342,532	$ 3,462,747	$ 2,936,314	$ 1,920,326	$ 2,472,047	$ 3,477,167	$ 3,134,047	$ 2,566,931	$ 3,539,293	$ 3,428,599	$ 3,169,478
Naughton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyodak	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Coal Fuel Burn Expense	$ 39,288,430	$ 3,696,668	$ 3,519,114	$ 3,672,452	$ 3,132,965	$ 2,144,880	$ 2,683,126	$ 3,706,734	$ 3,368,072	$ 2,784,430	$ 3,649,988	$ 3,561,533	$ 3,368,468
Gas Fuel Burn Expense													
Chehalis	$ 26,645,325	$ 4,543,319	$ 3,226,994	$ 2,325,251	$ 1,463,393	$ 1,460,941	$ 731,557	$ 1,947,546	$ 1,936,001	$ 1,620,118	$ 1,602,812	$ 2,552,445	$ 3,234,947
Currant Creek	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gadsby	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gadsby CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hermiston	$ 10,444,408	$ 1,483,626	$ 1,276,432	$ 619,738	$ 701,907	$ 333,832	$ 467,169	$ 606,214	$ 939,692	$ 902,312	$ 941,577	$ 1,139,623	$ 1,032,287
Jim Bridger – Gas	$ 25,757,321	$ -	$ -	$ -	$ -	$ 1,292,453	$ 2,920,445	$ 3,598,945	$ 3,822,704	$ 3,140,540	$ 3,384,632	$ 3,594,812	$ 4,002,790
Lake Side 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Side 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Naughton - Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Gas Fuel Burn	$ 62,847,055	$ 6,026,945	$ 4,503,426	$ 2,944,989	$ 2,165,300	$ 3,087,226	$ 4,119,172	$ 6,152,705	$ 6,698,397	$ 5,662,971	$ 5,929,021	$ 7,286,880	$ 8,270,024
Gas Physical	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas Swaps	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clay Basin Gas Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pipeline Reservation Fees	$ 3,898,888	$ 301,385	$ 317,472	$ 443,082	$ 332,846	$ 401,815	$ 404,197	$ 236,073	$ 208,614	$ 258,532	$ 496,570	$ 389,886	$ 108,416
Total Gas Fuel Burn Expense	$ 66,745,943	$ 6,328,331	$ 4,820,897	$ 3,388,071	$ 2,498,145	$ 3,489,040	$ 4,523,369	$ 6,388,778	$ 6,907,011	$ 5,921,503	$ 6,425,592	$ 7,676,766	$ 8,378,440

Other Generation													
Blundell	$ 329,287	$ 33,770	$ 17,437	$ 6,708	$ 31,584	$ 15,866	$ 29,803	$ 31,841	$ 32,774	$ 31,512	$ 30,567	$ 32,901	$ 34,523
Blundell Bottoming Cycle	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ 329,287	$ 33,770	$ 17,437	$ 6,708	$ 31,584	$ 15,866	$ 29,803	$ 31,841	$ 32,774	$ 31,512	$ 30,567	$ 32,901	$ 34,523
Net Power Cost	**$ 198,987,417**	**$ 28,167,855**	**$ 21,704,345**	**$ 16,477,207**	**$ 10,216,625**	**$ 11,460,111**	**$ 12,534,729**	**$ 18,788,342**	**$ 18,149,812**	**$ 14,397,500**	**$ 10,599,356**	**$ 14,029,356**	**$ 22,462,179**