

Confidential per WAC 480-07-160
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

1 **I. INTRODUCTION**

2 **Q. Please state your name, business address, and present position with PacifiCorp**
3 **d/b/a Pacific Power & Light Company (PacifiCorp or Company).**

4 A. My name is Ramon J. Mitchell, and my business address is 825 NE Multnomah
5 Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs and
6 I am testifying for PacifiCorp.

7 **II. QUALIFICATIONS**

8 **Q. Please describe your education and professional experience.**

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

16 **Q. Have you testified in previous regulatory proceedings?**

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

19 **III. PURPOSE OF TESTIMONY**

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

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

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

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

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

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

19 **Q. Please provide a summary of your direct testimony.**

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

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

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

6 **Q. How is the remainder of your testimony organized?**

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

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

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

22 Fourth, in Section X, I present a brief discussion on hedging and refer to the
23 2022 Power Cost Adjustment Mechanism (PCAM), which will expand on this issue.

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

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

6 IV. FORECAST NPC

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

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

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

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

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

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

22 **Q. What modeling inputs were updated for this filing?**

23 A. All inputs have been updated since the 2020 Rate Case, including system load,

1 reserves, wholesale sales and purchase contracts for electricity, natural gas and
2 wheeling, market prices for electricity and natural gas also known as the official
3 forward price curve (OFPC), fuel expenses, transmission topology, and the
4 characteristics and availability of the Company's generation facilities.

5 **Q. Did the Company update the regulation reserve input for this filing?**

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

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

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

11 **Q. What reports does the Aurora model produce?**

12 A. The major output from the Aurora model is the NPC report. An electronic version is
13 included in the workpapers accompanying the Company's filing. That NPC report
14 includes monthly data detailing major cost drivers.

15 **Q. What is the WIJAM?**

16 A. The Company recovers the costs of providing retail electric service to customers
17 through retail rates established in regulatory proceedings in each state. To ensure
18 states receive the appropriate allocation of costs and benefits from the Company's
19 integrated system, the collaborative Multi-State Process has been used to address
20 allocation issues. This collaborative process has led to the development and adoption
21 of a series of inter-jurisdictional cost allocation methods over time, with the most
22 recent being the 2020 Protocol. Washington has traditionally used a different
23 methodology than the Company's other jurisdictions, and this methodology was

1 known as the West Control Area Inter-Jurisdictional Allocation Methodology (WCA).
2 Along with the negotiations around the 2020 Protocol, the Company worked directly
3 with Washington Staff, Public Counsel, and the Packaging Corporation of America to
4 transition from the WCA to the WIJAM. In the order approving the 2020 Rate Case,
5 the Commission adopted the WIJAM for cost allocations in Washington.²

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

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

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

18 **V. DISCUSSION OF COST DRIVERS IN THE NPC FORECAST**

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

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

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

23 A. Washington allocated NPC begins with the total-company NPC forecast, which is
24 then allocated to Washington through the WIJAM. As noted above, NPC under the
25 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).

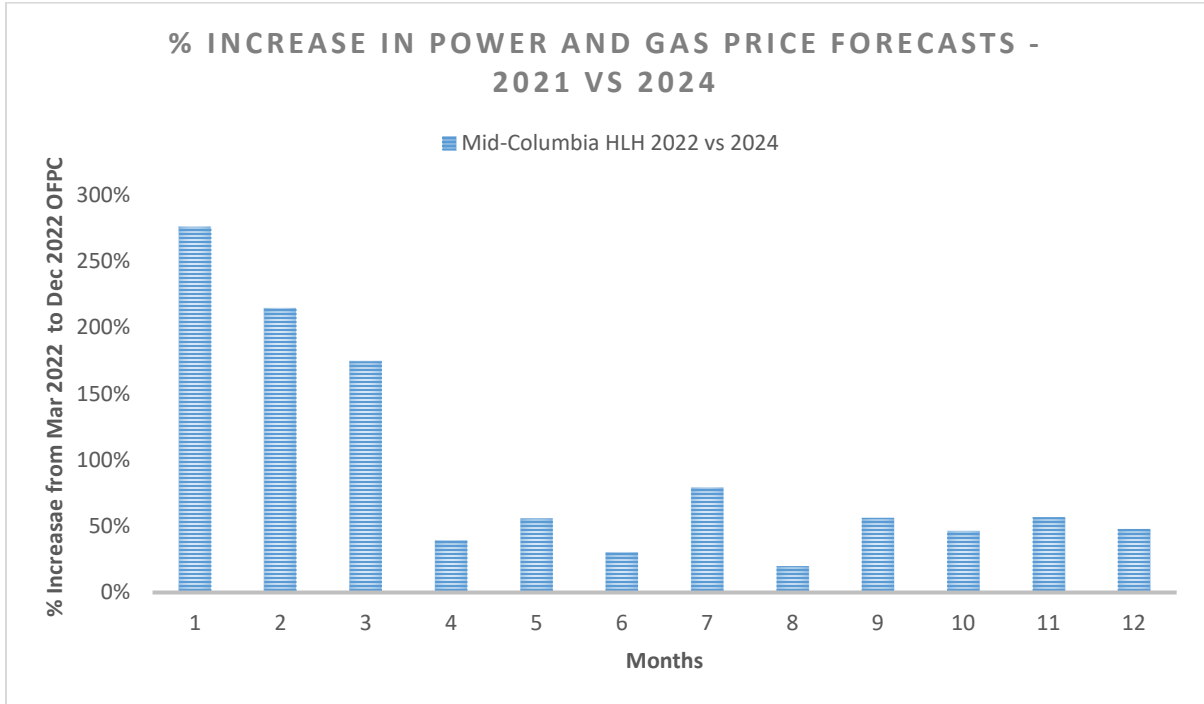
1 Washington rates. This method, based on relatively simple ratios and formulas, is
2 driven first and primarily by the total-company forecast and then by the WIJAM
3 specific allocations. Consequently, it is important to first understand the drivers of
4 NPC at the total-company level and then explore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

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

8 A. The NPC forecast from the 2021 PCORC used a March 31, 2022 vintage OFPC to set
9 the price expectations for calendar year 2022. Compared to calendar year 2024 price
10 expectations from the December 31, 2022 vintage OFPC, average power market
11 prices at Mid-Columbia increased by 80 percent as illustrated at the monthly
12 granularity in Figure 1 below. As a result of this, the four substantive changes to the
13 2024 landscape, and modeling improvements as discussed in more detail below in my
14 testimony, total-company NPC increased by \$1.08 billion or 74 percent, from a 2021
15 PCORC under-forecast of \$1.470 billion to this case's forecast of \$2.555 billion.

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

Figure 1



1

A. Regional Power Market Price Increases

2

Q. Why have regional power market prices increased?

3

A. Regional power market prices are lowered on average by increased penetration of

4

renewable resources across the western interconnection. However, renewable

5

resource construction across the nation has experienced delays relative to prior

6

expectations. Furthermore, expectations of continued abnormal weather conditions

7

have placed a premium on power market prices in the regional marketplace.

8

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

9

A. Global supply chain constraints have delayed production and transportation of key

10

components and equipment necessary for renewable resource construction across the

11

nation. Furthermore, increases in the prices of key renewable resource construction

1 commodities such as lithium, nickel and copper, as well as increases in labor costs
2 and interest rates, exacerbate the issue.

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

5 A. In the planning arena, at the regional level, renewable resource construction and
6 acquisition is assumed to partially offset the impact of thermal plant retirements on an
7 energy basis. In the short term, as the construction of these renewable resources are
8 delayed, thermal plant retirements continue on-schedule. The resulting energy
9 shortfall decreases supply without any associated decrease in demand (load).
10 Consequently, this triggers an energy price rise across the competitive regional power
11 markets.

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

13 A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of
14 the Pacific Northwest³ and the consequent decrease in expected hydroelectric
15 generation diminishes the expected regional energy supply.

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

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

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

3 **VI. NPC REPORT OVERVIEW**

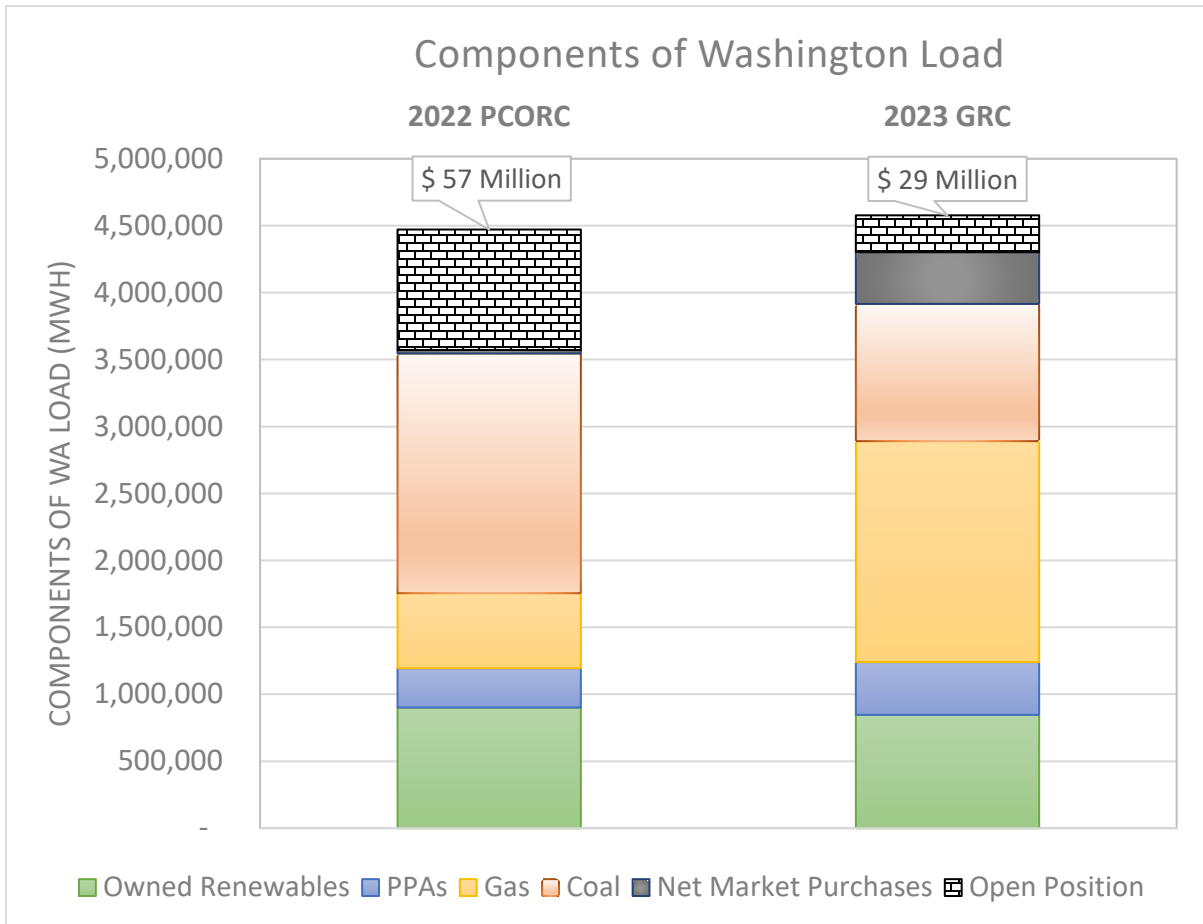
4 **Q. Considering that Washington does not take a share of all power generation**
5 **resources on PacifiCorp's system, please explain the spreadsheet-based WIJAM**
6 **adjustments necessary to balance supply and demand.**

7 A. Starting with the total-company NPC, Washington-allocated NPC are determined by
8 comparing the Washington load to the generation and market activity (resources) that
9 are allocated to Washington (*i.e.*, the resources that the WIJAM permits to be
10 allocated to Washington, which is less than all the resources on the system). In this
11 filing the Washington load exceeds Washington resources and this is shown as the
12 Shortfall in Table 1 below. This Shortfall is calculated on a monthly basis and creates
13 an open position, which is rebalanced in the WIJAM spreadsheet to arrive at the
14 Washington-allocated NPC. For Shortfalls, the rebalancing is done by first reducing
15 system balancing sales. If there are not sufficient system balancing sales to remove,
16 system balancing purchases are then added in by the amount needed for Washington
17 to maintain supply-demand balance. Any system balancing sales that are removed or
18 system balancing purchases that are added in the rebalancing adjustment are done
19 using the average price of either the system balancing sales or system balancing
20 purchases. Table 1 below shows the WIJAM megawatt-hour (MWh) balancing
21 adjustment in both the 2021 PCORC and the current filing while Figure 2 shows the
22 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



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

3 **A.** Illustrated below in Table 2 for costs and Table 3 for energy are the line item changes
 4 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	<u>1.93</u>	
Total Increase to NPC	53.80	
WA 2024 GRC Initial Forecast	<u>199.0</u>	43.47

Table 3

Net Power Cost Reconciliation (MWh)		
	MWh	\$/MWh
WA 2021 PCORC Final Forecast¹	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	<u>4,551,321</u>	43.47

1 **Q. Please explain the increase in purchased power expense.**

2 A. At the total-company level, the purchased power expense increases in tandem with
3 power market prices and increased purchased power volumes. The increase in
4 purchased power volumes is due to lower coal generation to comply with the Ozone

1 Transport Rule (OTR) generation limits, the decrease in generation at the Chehalis
2 plant due to the Washington Cap and Invest program, the outage for Jim Bridger
3 Units 1 and 2 to complete the gas conversion, increased regulation reserve
4 requirements and expectations of low hydroelectric generation. I explain these
5 individual drivers in more detail, below in my testimony.

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

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

13 A. At the total-company level, coal generation in both Wyoming and Utah is subject to
14 the new emissions limits in the OTR, resulting in a decrease in coal generation. The
15 remaining coal generation shows increased expense due to increases in coal price
16 expectations resulting from increased domestic competition for limited coal supply.
17 Natural gas generation increases due to the gas conversion of Jim Bridger Units 1 and
18 2 and increased dispatch of other gas units to meet load and reserve obligations left
19 behind after the decrease in coal and hydroelectric generation. Natural gas fuel
20 expense correspondingly increases in tandem with natural gas market prices.

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

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

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

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

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

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

17 VII. NPC VALIDATION

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

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

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

2 A. There is a clear and demonstrable relationship between total-company actual NPC
3 and regional power market prices. First consider Table 4 below which shows the
4 actual 2020 NPC, the actual 2021 NPC, the 2021 PCORC forecast of 2022 and the
5 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

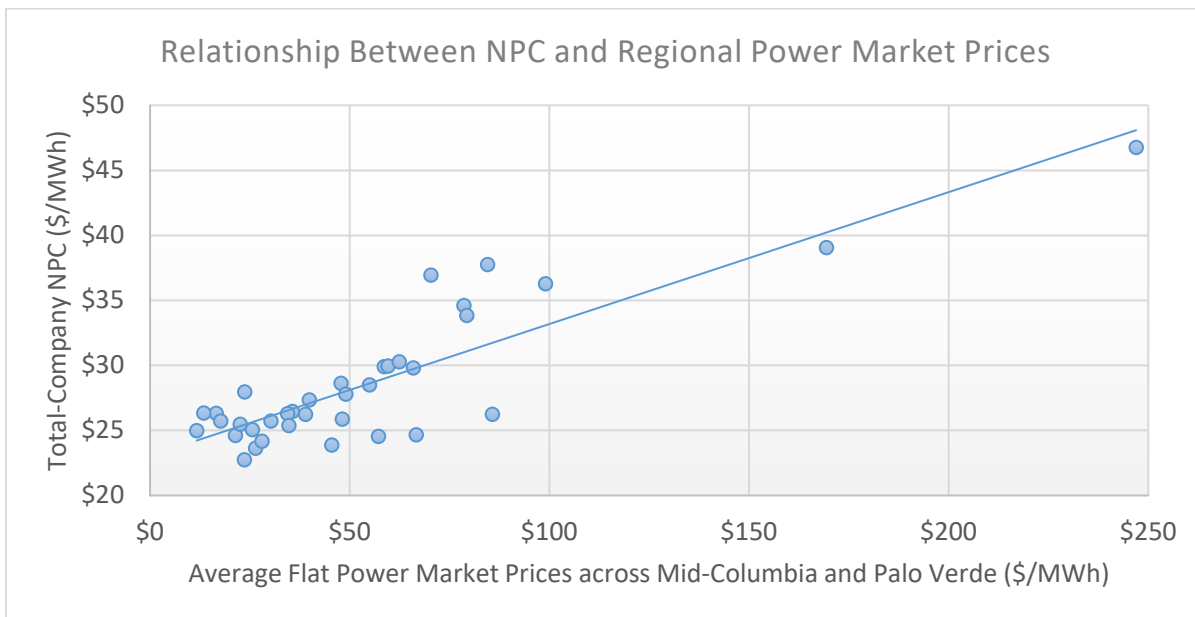
6 There are two items of note: (1) The 2021 PCORC NPC forecast of calendar year
7 2022 at \$1.470 billion, total-company, was substantially under-forecast (*i.e.*, less than
8 the actuals) relative to the actual calendar year 2022 NPC; and (2) within the actuals,
9 there is a clear upward trend in NPC.

10 **Q. Regarding the second layer, please elaborate on this upward trend in total-**
11 **company NPC and the associated extrapolation.**

12 A. Breaking actual NPC down to the monthly granularity it is observed that there is a
13 proportionate relationship between actual total-company NPC and regional power
14 market prices as illustrated below in Figure 3.

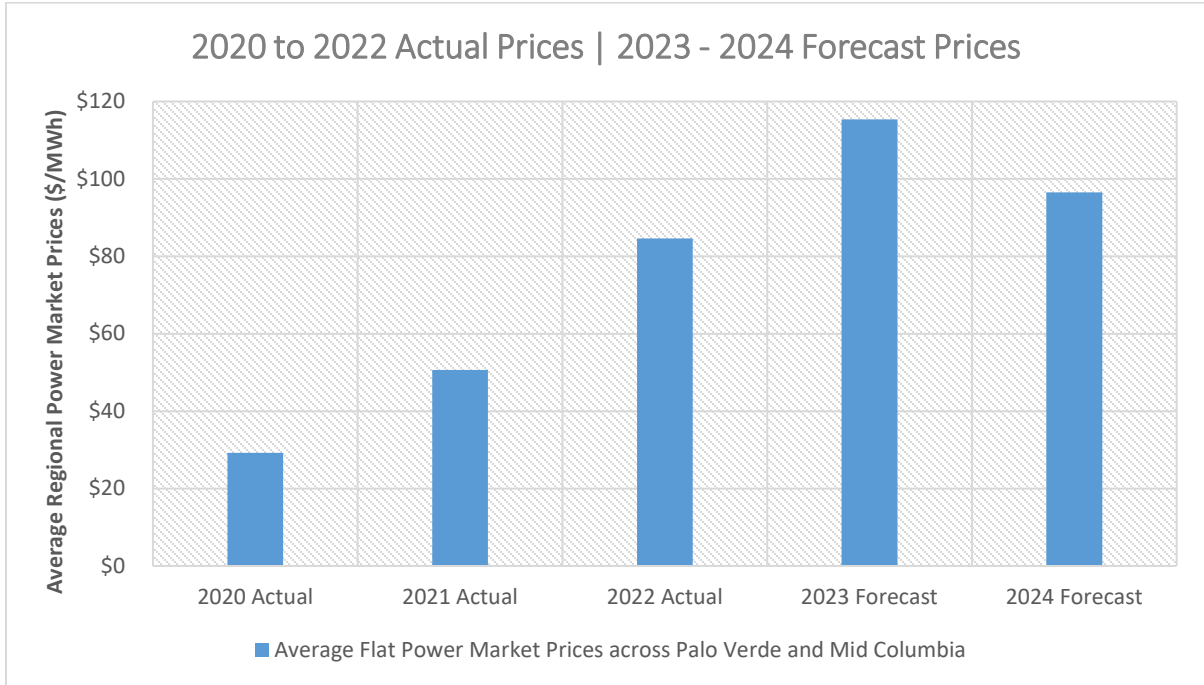
⁴ 2021 PCORC total-company NPC forecast without production factor adjustment.

Figure 3



1 To establish a reference baseline of what a reasonable total-company 2024 NPC
2 forecast (without any new operational or federal/state environmental compliance
3 requirements) might be, consider a simple extrapolation of the above relationship
4 between regional power market prices and total-company NPC. This extrapolation
5 suggests a total-company 2024 NPC of \$2.201 billion. Figure 4 below illustrates year
6 over year changes in actual and forecast regional power market prices that provide
7 context for the total-company NPC increases in Table 4 and context for the
8 extrapolation of total-company 2024 NPC at \$2.201 billion.

Figure 4



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

4 A. Total-company historical NPC and the corresponding relationship with regional
5 power market prices have not captured any of the cost impacts of four substantive
6 changes to the total-company 2024 landscape: (1) the expansion and revision of the
7 Environmental Protection Agency’s (EPA) Cross-State Air Pollution Rule on nitrogen
8 oxides’ (NO_x) emissions limits to encompass all generation in the states of Wyoming
9 and Utah (also referred to as the Ozone Transport Rule or OTR); (2) Washington’s
10 Cap and Invest program that subjects greenhouse gas (GHG) emissions to required
11 purchases of GHG allowances (decreasing the dispatch of the Chehalis gas-fired plant
12 located in Washington state); (3) the conversion of the Jim Bridger Units 1 and 2 from
13 coal-fired to gas-fired units; and (4) the removal of four hydroelectric projects along

1 the Klamath River. These four changes and their individual impacts to total-company
2 NPC are described in more detail, below in my testimony. In aggregate they increase
3 total-company NPC by \$353 million.

4 **Q. How do these three layers demonstrate the reasonableness of the total-company**
5 **NPC forecast?**

6 A. The historical actual NPC in combination with the proportionate relationship between
7 NPC and regional power market prices suggest that, absent any changes in federal or
8 state environmental compliance requirements or operations, \$2.201 billion is a
9 reasonable total-company NPC forecast for 2024. After layering on an additional
10 \$353 million (total-company) to account for the aforementioned upcoming federal
11 and state environmental compliance requirements and operational changes, which are
12 not reflected in the historical data, a reasonable benchmark for 2024 NPC becomes
13 \$2.554 billion (total-company) which is 0.06 percent below the proposed \$2.555
14 total-company NPC. This difference of 0.06 percent results from the use of a
15 relatively simple trend analysis as a reference for the total-company 2024 NPC
16 (absent federal and state environmental compliance requirements or operations
17 changes) as compared to the more detailed simulation within Aurora.

18 **VIII. ENVIRONMENTAL REQUIREMENTS AND OPERATIONS CHANGES**

19 **Q. What federal and state environmental requirements or operations changes are**
20 **forecast to have a substantial impact on 2024 NPC?**

21 A. There are five, which are: (1) the expansion and revision of the OTR on NO_x
22 emissions limits to encompass all generation in the states of Wyoming and Utah;
23 (2) the establishment of legislation in Washington, which drives GHG emissions

1 reductions through required purchases of GHG allowances; (3) the conversion of Jim
2 Bridger Units 1 and 2 from coal-fired to gas-fired units; (4) expectations of low
3 hydroelectric generation; (5) the construction of the Gateway South transmission line
4 (a portion of the Energy Gateway transmission expansion), which relieves
5 transmission limitations on the output wind generation in Wyoming.⁵

6 **A. The Ozone Transport Rule**

7 **Q. Please generally describe the OTR.**

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

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

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

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.

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

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

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

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

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

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

21 However, through the WIJAM, the Washington-allocated thermal generation
22 increases due to the Chehalis plant, the Hermiston plant and the Jim Bridger plant
23 increasing generation to offset the net generation decrease observed across Utah

1 thermal units. This results in a net increase to Washington-allocated thermal
2 generation, which lowers the WIJAM Shortfall and corresponding net open position.
3 The majority of the OTR generation loss in Utah is covered by the aforementioned
4 Washington-allocated thermal generation increases and only modest increases in
5 total-company purchased power are needed to cover the remaining OTR generation
6 loss. As a consequence, less market transactions are required to rebalance within the
7 WIJAM, with minimal offset from total-company purchased power, and the
8 Washington-allocated NPC *decrease* by \$8.2 million as a result.

9 **B. The Washington Cap and Invest Program**

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

11 A. The Washington Cap and Invest program is a market-based program, which began in
12 2023, designed to reduce carbon pollution and achieve greenhouse gas limits and
13 goals within Washington. The Chehalis gas-fired plant located in Washington is
14 directly impacted by this program within the NPC simulation, since, for each unit of
15 energy produced at the Chehalis plant there is an associated unit of GHG emissions
16 and for each unit of GHG emissions there is an associated GHG allowance cost.

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

19 A. There are two major impacts from the Cap and Invest program. The first impact is a
20 reduction to the forecasted Chehalis generation (due to the cost of the emissions
21 allowances required to operate the plant) and the associated NPC increase. This
22 increases the dispatch cost of Chehalis, which means that the output of the Chehalis
23 plant will decrease when compared to other generation sources with a lower dispatch

1 cost. The second impact is the removal of the cost of the emissions allowances in the
2 WIJAM to account for the no-cost allowances issued to the Company for Washington
3 load service and the associated NPC decrease.

4 **Q. What is the GHG allowance cost applied to the Chehalis plant for calendar year**
5 **2024?**

6 A. The GHG allowance cost is currently estimated at 24.75 dollars per MWh (\$/MWh)
7 for calendar year 2024 based on an independent analysis commissioned by
8 Washington's Department of Ecology.⁶ The program commences at the beginning of
9 2023, the first auction will take place in the second half of February 2023 and results
10 will be published in March 2023. The NPC forecast will be updated with refreshed
11 prices in the NPC update.

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

14 A. As previously mentioned, the emissions allowance cost for Chehalis is currently
15 estimated at \$24.75/MWh for calendar year 2024 based on an independent analysis
16 commissioned by Washington's department of Ecology through Vivid Economics.
17 After application of the estimated emissions allowance cost to the Chehalis plant,
18 Washington-allocated NPC increases by \$16.8 million. Then, after removing the
19 emissions allowance cost in the WIJAM, Washington-allocated NPC decreases by
20 \$15.4 million. The delta between the increase and the decrease (\$1.3 million) is
21 primarily attributable to the increase in the WIJAM Shortfall due to the reduction in
22 Chehalis generation.

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

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

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

10 **C. Jim Bridger's Gas Conversion**

11 **Q. Please describe what is taking place at Jim Bridger Units 1 and 2.**

12 A. Jim Bridger Units 1 and 2 are proposed to be converted to gas-fired units. Currently,
13 these two units are coal-fired. The Company's proposal to convert Jim Bridger Units
14 1 and 2 was filed in a separate application on December 9, 2022, and is a pending
15 case with the Wyoming Public Service Commission.⁷

16 **Q. Why are Jim Bridger Units 1 and 2 being converted to gas?**

17 A. Emissions requirements imposed by the EPA required the installation of a selective
18 catalytic reduction system to reduce NO_x emissions from Jim Bridger Units 1 and 2
19 for continued coal-fired operations.⁸ Past December 31, 2023, gas conversion was
20 identified as a more economically viable option in the long-term analysis of the

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).

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

3 **Q. What is the Washington-allocated impact to NPC of this conversion?**

4 A. There are two impacts. The first impact is the result of replacing the coal-fired units
 5 with similarly sized gas-fired units, all other things equal. The impact of this
 6 adjustment is an increase of \$4.5 million. This increase is driven by the fact that
 7 natural gas fuel is on average more expensive than coal fuel. The second impact is the
 8 result of the outage period necessary to accomplish the gas conversion. With both
 9 units being on outage from [REDACTED] there is a \$8.0 million
 10 increase to NPC. This increase is driven by increased market purchases to cover the
 11 generation loss.

12 **Q. Why are the NPC impacts of the Jim Bridger Units' gas conversion separated
 13 into two components?**

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

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

22 A. Through the WIJAM, the Washington-allocated thermal generation decreases
 23 substantially because of the combined outage at Jim Bridger Units 1 and 2. This

1 increases the WIJAM Shortfall and corresponding net open position. Therefore, more
2 market transactions are required to re-balance within the WIJAM as compared to a
3 scenario in which the outage didn't take place at all.

4 **D. Hydroelectric Generation Reduction**

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

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

10 **Q. Why has hydroelectric generation decreased by 18 percent?**

11 A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of
12 the Pacific Northwest⁹ and is picked up in the normalized hydroelectric generation.
13 Additionally, the pending removal of the four Company-operated hydroelectric
14 projects¹⁰ along the Klamath river contributes to this decrease. These projects total
15 approximately 180 megawatts of capacity and will cease operations by the end of
16 2023. The removal of these projects are discussed in further detail in the testimony of
17 Company witness Sherona L. Cheung.

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

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

⁹ See *U.S. Drought Monitor*, *supra* note 1.

¹⁰ J.C. Boyle, Copco 1, Copco 2, and Iron Gate hydroelectric projects.

1 **E. Gateway South Transmission Project**

2 **Q. What is the Gateway South Transmission Project?**

3 A. As part of the Company’s Energy Gateway transmission expansion, the Company is
4 planning to build a 500-kilovolt high-voltage transmission line, known as Gateway
5 South, extending from the Aeolus Substation in southeastern Wyoming into the
6 Clover Substation near Mona, Utah.

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

8 A. The Gateway South Project will meet load growth, provide increased reliability, and
9 improve operational flexibility in conjunction with future generation resources,
10 including renewable energy. Specifically, it will allow for the release of “trapped
11 energy” from wind resources in Wyoming. The concept of trapped energy is
12 discussed in more detail, below in my testimony.

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

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

18 **IX. MODELING IMPROVEMENTS TO THE NPC FORECAST**

19 **Q. Why are modeling improvements necessary?**

20 A. Modeling improvements are needed to align the NPC forecasting methodology to
21 operational realities for the purpose of increasing accuracy of the NPC forecast. In the
22 2021 PCORC compliance filing submitted on April 15, 2022, based on the March
23 2022 OFPC, the Company forecasted total-company NPC for calendar year 2022 at

1 \$1.470 billion (absent production factor adjustment). Actual NPC for calendar year
2 2022 was recorded at \$2.041 billion, an under-forecast of \$570 million relative to the
3 PCORC forecast.

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

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

- 7 • The DA/RT market price adder will be changed from a flat value to a
8 percentage.
- 9 • Trapped energy will be appropriately substituted for curtailment of generation
10 to reflect actual operations.
- 11 • The maximum capacity of certain thermal generation units will be updated to
12 reflect ambient derates to unit capacity during the summer months.

13 **A. DA/RT Adjustment - Price Component**

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

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

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

1 indexed market prices. Previously these prices were calculated by adding or
2 subtracting a flat dollar amount to the hourly scaled prices from the OFPC.

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

6 A. Changing the price calculation to a percentage of the market prices aids in accounting
7 for the volatility caused by prices and system conditions not captured in day-ahead
8 transactions. Take, for example, a \$5 price adder in an hour when the market price is
9 \$25. This resolves to a 20 percent price adder. But using the \$5 price adder when
10 market prices are \$75 would fail to account for the system and market conditions
11 during that hour. Using a 20 percent price adder during hours when market price is
12 \$75 would yield in a \$15 price adder, which is more reflective of the system
13 conditions. A key benefit of using a percentage adder is that it allows the modeling to
14 capture intra-month variability. Consequently, this is a more accurate representation
15 of real operating conditions experienced by the Company.

16 **Q. Please quantify the impact of this adjustment.**

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

20 However, a consequence of this adjustment at the total-company level is that
21 the average price (\$/MWH) of wholesale sales decreases by a modest amount, which
22 lowers the cost of re-balancing the shortfall in the WIJAM to close the net open

1 position. Consequently, in the WIJAM the impact of this adjustment *decreases*
2 Washington-allocated NPC by \$0.18 million as a result.

3 **B. Trapped Energy**

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

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

13 **Q. Why was the trapped energy modeling concept necessary in the old Generation
14 and Regulation Initiative Decision Tools (GRID) model?**

15 A. Conceptually, the trapped energy zones allow for a feasible model solution in the
16 event of an inability to maintain the supply/demand balance when there is excess
17 supply. However, the primary function of trapped energy zones in prior GRID NPC
18 simulations was to allow for Company-owned production tax credit (PTC) eligible
19 wind to be modeled with a reasonable degree of accuracy. Due to an inability in
20 GRID to model resources with a negative dispatch cost (representative of PTCs, in
21 the case of wind), these wind resources could not provide the proper price signal to
22 the model and therefore could not be accurately represented within GRID's resource
23 stack. As a work-around, the wind resources were simulated as must run resources

1 and all excess wind generation within a transmission constrained area was funneled
2 into a trapped energy zone.

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

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

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

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

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

18 A. The impact of allowing for realistic wind curtailment is a Washington-allocated
19 increase to NPC of \$3.9 million driven by: (1) a reduction in pseudo-wholesale sales
20 revenue earned from the sales of energy derived from a modeling construct that does
21 not exist in actual operations; and (2) incremental wind curtailments to maintain the
22 supply/demand balance within a transmission congested region when considering that

1 any sharp hour-to-hour ramps in wind generation are unable to be completely
2 balanced by relatively slow ramping coal units present in the region.

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

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

8 **C. Thermal Attributes**

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

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

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

19 A. Because maximum capacities of some thermal plants are reduced as a result of
20 increased temperatures in the summer, not adjusting the capacity during the summer
21 months based on these conditions would result in Aurora overstating plant capacity
22 and generation output, which would consequently understate the need to dispatch
23 higher cost units or increase purchases to serve load during the summer months.

1 Reducing generation capacity during summer based on average summer temperatures
2 is reflective of actual ambient-temperature constraints.

3 **Q. Please quantify the impact of this adjustment.**

4 A. The impact of this adjustment is a Washington-allocated increase to NPC of \$1.7
5 million. This increase is driven by increased market purchases.

6 **X. HEDGING**

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

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

15 **Q. How does the Company hedge for Washington customers?**

16 A. The Company hedges its entire system holistically. There is no separate hedge book
17 for transactions allocated to Washington specifically. In this filing, Washington's
18 allocation of generation resources remains short against Washington load and,
19 consequently, approximately 6 percent of Washington load has to be satisfied using
20 modeled market interactions through the WIJAM. For context, consider that in the
21 2021 PCORC, approximately 20 percent of Washington load had to be satisfied using
22 modeled market interactions, which shows a substantial filing-over-filing reduction to
23 Washington's market exposure.

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

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

6 **XI. JIM BRIDGER AND COLSTRIP IN RATES**

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

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

14 Within this context, the Company assessed the NPC impacts of a scenario in
15 which Jim Bridger Units 3 and 4 (the coal portions of Jim Bridger) and Colstrip Unit
16 4 (Colstrip) were excluded from the NPC forecast as compared to a scenario in which
17 the aforementioned resources were included. This analysis demonstrates substantial
18 benefits to Washington customers from the inclusion of these resources in the NPC
19 forecast.

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

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

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

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

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

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

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

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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 \$45.7¹¹ 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.

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

3 **A. Jim Bridger Coal Costs**

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

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

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

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

11 **Q. What are the coal cost changes at BCC?**

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

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

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

1 **Q. Did the Black Butte coal price increase in calendar year 2024 as compared to the**
2 **2021 PCORC?**

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

6 **B. Colstrip Unit 4 Coal Costs**

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

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

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

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

14 **XIII. NPC UPDATES ACROSS THIS MULTI-YEAR PLAN**

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

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

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

22 A. Yes, please refer to Table 5 below, which details the schedule for the three NPC
23 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

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

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

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

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

13 A. First, forward prices for natural gas and electricity will be updated in Aurora itself. In
14 addition, hedge positions for power and gas will be updated based on the most recent
15 month-end hedge positions available, and any mark-to-market values will be updated
16 to reflect the use of the same OFPC that was described in the first step. Any new
17 power purchase agreements and Qualifying Facility contracts will be included in the
18 model, and any required updates to contracts that were previously included will be

1 made. Finally, Energy Imbalance Market (EIM) transfer and greenhouse gas (GHG)
2 benefits will be reforecast, also based on the same OFPC, to synchronize the NPC
3 inputs for the most accurate output.

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

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

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

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

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

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

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

4 A. No.

5 **XIV. CONCLUSION**

6 **Q. What actions are you recommending the Commission take?**

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

11 **Q. Does this conclude your direct testimony?**

12 A. Yes.