**BEFORE THE WYOMING PUBLIC SERVICE COMMISSION**

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| **IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES BY APPROXIMATELY $140.2 MILLION PER YEAR OR 21.6 PERCENT AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM** | **DOCKET NO. 20000-633-ER-23 (Record No. 17252)** |

**NON-CONFIDENTIAL DIRECT TESTIMONY**

**AND EXHIBITS**

**OF**

**BRADLEY G. MULLINS**

**On Behalf of**

**Wyoming Industrial Energy Consumers**

**August 14, 2023**

**WIEC Exhibit No. 202**

**CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN**

**DOCKET NO. 20000-633-ER-23**

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## I. INTRODUCTION AND SUMMARY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Bradley G. Mullins. My business address is Tietotie 2, Suite 208, Oulunsalo, FI-90440 Finland.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am the Principal Consultant for MW Analytics, an independent consulting firm representing utility ratepayers before state public utility commissions in the Western United States.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of the Wyoming Industrial Energy Consumers ("WIEC"), an unincorporated trade association whose members are large energy users located in Wyoming, including ratepayers receiving electrical services from Rocky Mountain Power ("RMP" or the "Company").

**Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.**

A. I have been performing independent energy and utilities consulting services for approximately 10 years. I have sponsored expert witness testimony in over 100 regulatory proceedings on a variety of subject matters, including revenue requirements, regulatory accounting, rate development, and new resource additions. I have a Master of Accounting degree from the University of Utah. A qualification statement and list of recent regulatory appearances can be found in **WIEC Exhibit No. 202.1**.

**Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

A. I discuss RMP's proposed forecast of Net Power Cost ("NPC") for the twelve months ending December 31, 2024 ("Test Period"). I review the reasonableness of the forecast assumptions presented in the Direct Testimony of RMP witness Mitchell,[1] as well as the revised forecast submitted in the July 24, 2023 Supplemental Direct Testimony of RMP witness Mitchell (the "July Update").[2] I present and discuss my proposed forecast of NPC for the Test Period, along with discussion of problematic forecast assumptions included in RMP's forecast. Finally, I present several revenue requirement recommendations, other than NPC, which are incorporated into the overall revenue requirement recommendation presented by WIEC witness Kevin C. Higgins.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A. Based on its July Update, RMP has proposed an NPC forecast of $2.54 billion on a total-company basis, or $357.8 million Wyoming-allocated. Notwithstanding the fact that market prices in the Test Period are forecast to be lower than 2022 market prices, this forecast represents a $500.0 million, or a 24.5%, total-company increase relative to the $2.04 billion of *actual* NPC in 2022. RMP's forecast in this case represents an even greater total-company increase of $1.11 billion, or 77.3%, when

[1] Direct Testimony of Ramon Mitchell, RMP Exhibit 10.0.
[2] Supplemental Direct Testimony of Ramon Mitchell, RMP Exhibit 10.4.

compared back to the NPC forecast approved in the 2020 general rate case ("GRC").[3] These proposed increases are staggering.

As I discuss below, however, the significant increase to NPC RMP has forecast relative to 2022 actual NPC is not justified. While my forecast still supports a large increase to NPC relative to the 2020 GRC, my analysis shows that more reasonable assumptions produce an NPC forecast that is in line with 2022 actual NPC. Based on the forecast presented in **WIEC Exhibit 202.2,** I recommend Test Period NPC of $2.00 billion on a total-company basis, which equates to $282.1 million Wyoming-allocated. The differences between my forecasting method and RMP's have been detailed in **Table BGM-1**, below, and brief descriptions of the differences follow the table.

[3] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4*, Docket No. 20000-578-ER-20 (Record No. 15464).

**Table BGM-1**
Recommended Test Period NPC Forecast, Whole Dollars

| | | Total Company | Wyoming Allocated |
|---|---|---|---|
| 1 | **RMP July Update NPC Forecast** | **2,540,351,036** | **357,800,000** |
| 2 | **Modeling Differences:** | | |
| 3 | Initial Filing Coal Costs | (115,225,600) | (15,843,014) |
| 4 | AURORA Model Environment | (2,094,140) | (287,935) |
| 5 | Washington CCA | (69,523,712) | (9,559,205) |
| 6 | DA/RT: July Update Method Change | (80,199,295) | (11,027,051) |
| 7 | DA/RT Method Simplification | (17,141,121) | (2,356,829) |
| 8 | Market Caps - Liquid Markets | (20,974,080) | (2,883,844) |
| 9 | Market Caps - 95th Percentile | (17,091,156) | (2,349,959) |
| 10 | Ozone Transport Rule | (17,961,132) | (2,469,577) |
| 11 | Non-Native Reserves | (210,694,263) | (28,969,536) |
| 12 | **Total Modeling Differences** | **(550,904,499)** | **(75,746,951)** |
| 13 | **Mullins NPC Forecast** | **1,989,446,537** | **282,053,049** |

- *Initial Filing Coal Costs:* My forecast is based on the coal budgets RMP submitted in its initial filing because no documentation or supporting workpapers were provided to support the reasonableness of the significant cost increases made in the July Update. RMP also materially misstated the impact of the coal cost update in the July Update, which is further reason to rely on the originally filed budgets.

- *Aurora Model Environment:* The AURORA model run by my computer architecture produces a slightly lower result than RMP's, which I have captured in the above table.

- *Washington Climate Commitment Act ("CCA"):* My forecast removes the modeled cost of purchasing allowances for compliance with the Washington CCA for the Chehalis power plant.

- *Day-ahead/Real-time ("DA/RT") – July Update Method Change:* I reversed RMP's changes to the DA/RT method included in the July Update because changes were not appropriate for an update filing and were not documented or explained in Supplemental Direct Testimony.

- *DA/RT – Method Simplification:* I also simplified the DA/RT modeling method to be an out-of-model adjustment because it was producing inaccurate system dispatch in the AURORA model.

- *Market Caps – Liquid Markets:* I modified hub demands (formerly called "market caps") to eliminate restrictions on liquid market hubs, consistent with how the method has been performed in the past.

- *Market Caps – 95$^{th}$ Percentile:* I adjusted the formula to calculate the limit on other markets based on a 95th percentile, which produced modeled sales that were more consistent with historical levels.

- *Ozone Transport Rule:* I removed the environmental restrictions RMP modeled with respect to the EPA ozone transport rules because they will not apply to Wyoming in the Test Period and are subject to ongoing litigation in Utah.

- *Non-Native Reserves:* I limited the costs of serving non-native loads and third-party variable energy resources to RMP's Federal Energy Regulatory Commission ("FERC") approved Open Access Transmission Tariff ("OATT") rates.

**Q. WHAT RECOMMENDATIONS ARE YOU SPONSORING FOR NON-NPC REVENUE REQUIREMENT ITEMS?**

A. With respect to revenue requirement recommendations other than NPC, I am sponsoring the following recommendations:

- *State Income Tax:* Since RMP does not pay any material state taxes, I recommend transitioning to a flow-through method of accounting for state taxes, which will limit the state taxes included in rates to the state taxes that RMP pays. In conjunction with this request, I propose a mechanism to refund previously accrued Accumulated Deferred State Income Taxes ("ADSIT") to ratepayers.

- *Jim Bridger Units 1 and 2 Gas Conversion:* I recommend that the operating expenses of Jim Bridger 1 and 2 be removed during the approximate three-month period when removed from service for conversion into a gas fired steam generator.

- *Production Tax Credit ("PTC") Rate:* I present my forecast of the PTC rate for 2024 and recommend that it be increased to 3.0 cents per kWh.

## II. BACKGROUND

**Q. WHAT IS NPC?**

A. For RMP, NPC represents the variable energy costs associated with providing electric services. It includes the cost of fuel (both coal and gas), the cost of purchased power, and the cost of wheeling (*i.e.*, the cost of transmitting electricity on other utilities' transmission systems). It also includes the revenues associated with power sales in wholesale markets, including long-term power sales agreements and short-term sales in regional markets. The *net* in NPC, therefore, is representative of the fact that it includes wholesale sales transactions that offset the variable energy costs of serving retail customers. The specific FERC Accounts included in NPC include the following:

- Account 447 – Sales for Resale;
- Account 501 – Fuel (for Steam Power);
- Account 503 – Steam from Other Sources (Geothermal);
- Account 547 – Fuel (for Mechanical Power);
- Account 555 – Purchased Power; and
- Account 565 – Wheeling.[4]

**Q. HOW DOES RMP FORECAST NPC?**

A. RMP forecasts NPC with an hourly production cost model that uses a numerical representation of the Company's system to simulate system dispatch based on assumed forecast parameters, such as loads, fuel prices, and wholesale market

[4] Uniform System of Accounts Prescribed For Public Utilities And Licensees Subject to The Provisions of The Federal Power Act, 18 CFR 101.

prices. Prior to this proceeding, RMP has used a production cost model known as the Generation Regulation and Incentives Decision ("GRID") tool. The GRID model was developed internally by RMP and had been used since around 2001. In this proceeding, RMP has proposed using a new, third-party developed model known as AURORA.

**Q. DOES AURORA FUNCTION THE SAME WAY AS GRID?**

A. While the AURORA model is similar in some ways to the GRID model, it uses a different approach for simulating system dispatch. The GRID model used an approach referred to as "least cost dispatch," where it optimized the costs of serving loads subject to transmission and other constraints. The AURORA model, by contrast, uses an approach referred to as "merit order," where the model selects resources to dispatch depending on their dispatch cost relative to other resources. From a forecasting perspective, both approaches have strengths and weaknesses. In general terms, the least-cost dispatch approach used by the GRID model produced a more optimized system dispatch. By RMP's account, the dispatch from the GRID model was overoptimized, justifying a number of modeling techniques meant to rein in the optimization.[5] The AURORA model, on the other hand, produces more relaxed system dispatch, and therefore, the concerns about over-optimization are not necessarily as pertinent for AURORA. As I discuss below, applying the same modeling techniques as applied to GRID to the AURORA model produces inconsistent results that do not align with RMP's actual operations.

[5] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent*, Docket No. 20000-469-ER-15 (Record No. 10476), Rebuttal Testimony of Brian S. Dickman, p. 33, lines 13-19.

**Q. WHAT LEVEL OF NPC HAS RMP FORECAST?**

A. Using the new AURORA model, RMP has forecast NPC of $2,540,351,036 for the test period.[6] As I note in the introduction, this represents a significant increase both relative to actual NPC incurred in 2022, as well as to the NPC forecast approved in the 2020 GRC. While increases are expected relative to the 2020 GRC due to the changes in market conditions that have occurred since early 2020, changing market conditions do not support an increase relative to the actual cost incurred in 2022, which is a more relevant consideration when evaluating the reasonableness of the NPC forecast. Market rates had already increased in 2022 and are, in fact, now declining.

**Q. WHAT IS DRIVING THE INCREASE IN NPC?**

A. According to RMP, the increase in NPC is being caused by "regional power and gas market prices" that have "increased to such extraordinary highs."[7] According to RMP witness Mitchell, "[t]he primary driver" of this increase "is the conflict in Ukraine which has decreased European availability of natural gas."[8]

**Q. IS WAR IN UKRAINE THE CAUSE OF THE INCREASED FORECAST?**

A. No. Attributing the increase in NPC in this matter to the war in Ukraine represents a shallow view of Western energy markets. European natural gas supplies are only directly connected to domestic energy markets through liquified natural gas ("LNG") exports, which occur predominantly in the gulf-coast, near the Henry Hub gas market. These exports have only limited price impacts on gulf markets and

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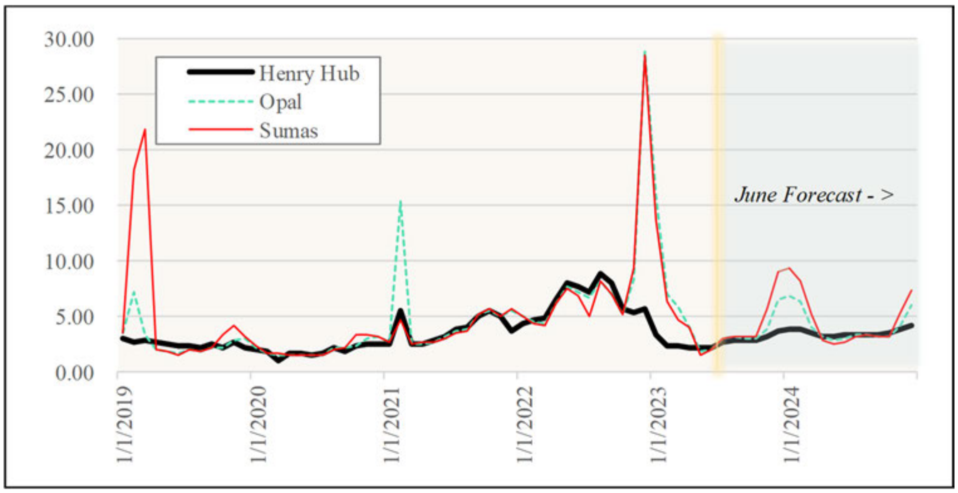
[6] Supplemental Direct Testimony of Ramon Mitchell, RMP Exhibit 10.5, p. 6.
[7] Direct Testimony of Ramon Mitchell, p. 12, lines 20-21.
[8] *Id.* at p. 13, lines5-6.

even less impact on Western markets. Further, the Henry Hub gas market has not experienced the same degree of price volatility as the West, meaning that exports of LNG to Europe have not been the primary cause of heightened prices in the West. This is demonstrated in **Figure BGM-1**, below.

**Figure BGM-1**
Natural Gas Prices 2019 – 2022: Henry Hub, Opal, &. Sumas
($/dth)

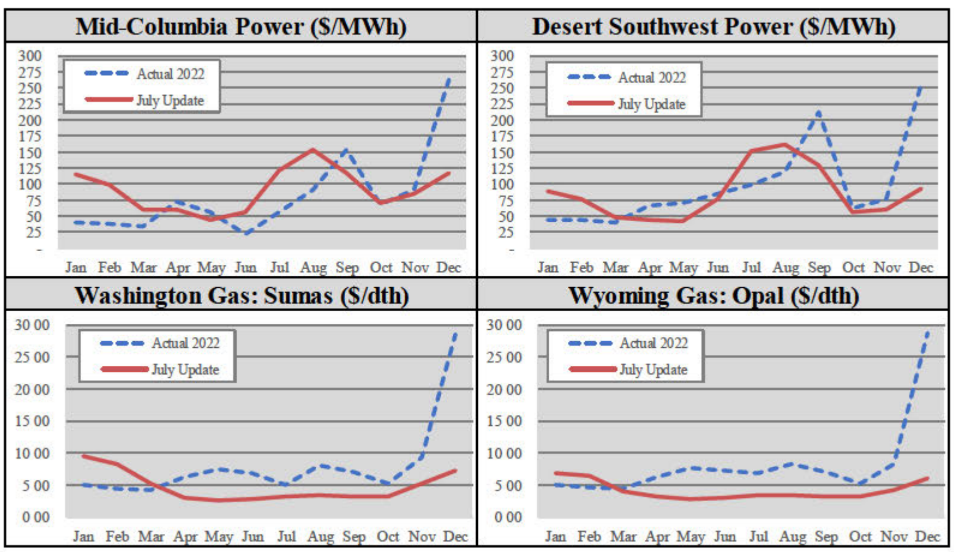



While Henry Hub is in Louisiana, Opal is located in Lincoln County, Wyoming, and Sumas is located on the Washington/British Columbia border. As can be seen, prices in the West have been materially more volatile and higher than Henry Hub prices, particularly in winter months. It is possible that geopolitical issues might have had some impact gas prices in 2022, particularly with respect to the interplay between coal and gas prices. Notwithstanding, prices at Henry Hub have since normalized, declining to pre-pandemic levels, although winter price spikes are still being forecast in the West. Therefore, exports into Europe, and correspondingly the war in Ukraine, are not a valid explanation for heightened forecast market prices in the West, nor an explanation for the increase to forecast NPC in this proceeding.

**Q. DOES THE CHANGE IN MARKET PRICES JUSTIFY THE LARGE INCREASE THAT RMP IS FORECASTING?**

A. No. There is no question that market conditions have changed since the 2020 GRC. Relative to 2022, however, prices have *declined* materially. This is detailed in **Figure BGM-2**, below.

**Figure BGM-2**
Change in Western Energy Market Prices: 2022 vs 2024 (forecast)

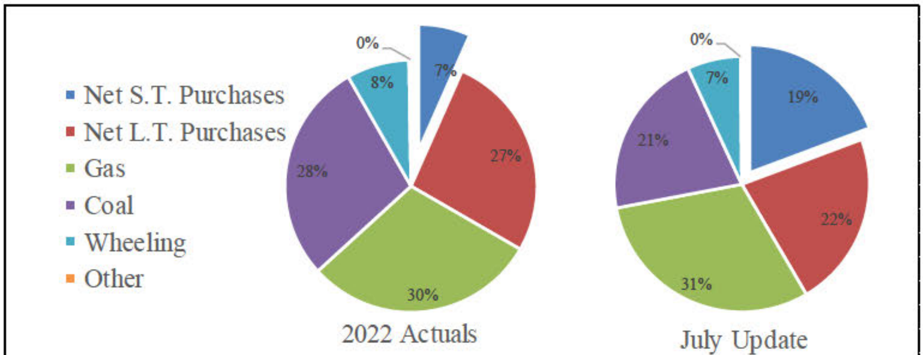



Thus, while the energy prices may justify a higher NPC relative to the 2020 GRC, they are not an explanation for RMP's forecasted 24.5% increase to NPC relative to 2022 actuals. On average, Sumas gas prices, for example, are forecast to be approximately 20% lower than 2022 levels. After considering the large increases in zero fuel costs renewable resources coming online in the test period, the relationship above would otherwise imply that the forecast NPC for the Test Period should be *lower* than 2022 actuals.

**Q. WHAT IS CAUSING RMP'S FORECAST TO BE HIGHER THAN 2022 ACTUALS.**

A. Actual NPC for calendar year 2022 has been attached as **WIEC Exhibit 202.3.** In **Figure BGM-3**, below, I provide a comparison between RMP's forecast and 2022 actual NPC. For purposes of this analysis, short-term purchases and sales were netted to form an apples-to-apples comparison to the modeled results.

**Figure BGM-3**
2022 Actual NPC vs. July Update Model Forecast




| Category | 2022 Actuals | July Update | Variance | % |
|---|---|---|---|---|
| Net S.T. Purchases | $ 135,625,310 | $ 490,758,407 | $ 355,133,097 | 262% |
| Net L.T. Purchases | 544,173,647 | 565,127,730 | 20,954,082 | 4% |
| Gas | 610,525,466 | 773,580,775 | 163,055,308 | 27% |
| Coal | 580,834,961 | 535,116,619 | (45,718,342) | -8% |
| Wheeling | 164,088,727 | 171,444,115 | 7,355,388 | 4% |
| Other | 5,070,191 | 4,323,390 | (746,801) | -15% |
| **Total** | **$ 2,040,318,302** | **$ 2,540,351,036** | **$ 500,032,733** | **25%** |

In **Figure BGM-3**, it can be observed that the most significant variance between 2022 actual NPC and the July Update was the Net Short Term Purchases category. While market prices declined slightly relative to actuals, RMP's modeled forecast assumed net short-term purchases that are $355,133,097 higher than actuals, a variance of 262%. This is an indication that the AURORA model, as configured by RMP, is not accurately forecasting the costs and revenues associated with short term purchases and sales, and thereby, inflating the level of NPC included in the forecast. This result is likely being caused in part by some of the modeling techniques discussed below, such as the DA/RT and market cap modeling methods.

Further, another variance can be found in the cost of gas, which increases by 27%. This increase can be attributed in part to gas hedging transactions that offset actual NPC in 2022, which are not included in the Test Period. Moreover, the conversion of Jim Bridger Units 1 and 2 to a gas fired steam generator is likely another cause of the increase to gas costs. With an increase to gas production, coupled with new renewable resource generation, one would otherwise expect Net Short-Term Purchases to decline. However, that is not occurring in the model.

**Q. WHAT ARE YOUR OBSERVATIONS BASED ON THIS COMPARISON?**

A. This comparison demonstrates that RMP's implementation of the new AURORA model is producing an NPC forecast that is overstated. To be clear, there are factors that might lead to increased NPC in the Test Period relative to 2022, including the Jim Bridger Units 1 and 2 gas conversion and expiration of favorable gas hedges. Notwithstanding, my analysis shows that more favorable market conditions discussed above are offsetting to these factors. Based on my modeling, which adopts a different approach to some of the modeling techniques RMP has used, I arrived at a forecast that produces a result that are consistent with 2022 actual NPC. Before discussing those, however, it is necessary to address problems identified with RMP's July Update.

## III. JULY UPDATE

**Q. PLEASE PROVIDE AN OVERVIEW OF THE JULY UPDATE.**

A. Pursuant to the procedural schedule, RMP submitted an updated NPC forecast on July 24, 2023.[9] At the time of RMP's initial filing on March 1, 2023, it had forecast NPC based on the Official Forward Price Curve ("OFPC") dated December 31, 2022.[10] The OFPC is a market price forecast that RMP files quarterly based loosely on traded prices in forward markets. At the time, the December 31, 2022 OFPC was issued, markets were elevated and volatile due to gas shortage conditions on the West coast. This can be noted through the price spikes at that time in both **Figure BGM-1** and **Figure BGM-2**, above. Faced with these abnormal conditions, WIEC was supportive of performing an update to forward prices using the June 30, 2023 OFPC. There was some expectation that markets would return to more normal conditions in the intervening period.

**Q. WAS THE JULY UPDATE SUPPOSED TO INCLUDE NEW MODELING CHANGES?**

A. No. It was WIEC's expectation that the July Update would not include new modeling techniques and that any proposed updates would be thoroughly documented with testimony and supported with contemporaneously filed workpapers. Unfortunately, that was not the case. As I discuss below, the July Update is problematic because it included several new, undocumented modeling method changes, as well as significant changes to coal costs, which were neither

[9] *See* Supplemental Direct Testimony of Ramon Mitchell.
[10] Direct Testimony of Ramon Mitchell, p. 5, line 20.

discussed in Supplemental Direct Testimony, nor supported with the established workpapers required pursuant to Commission Order in Docket No. 20000-352-ER-09.[11]

**Q. WHAT WAS THE IMPACT OF THE JULY UPDATE ON RMP'S FORECAST?**

A. The July Update reduced RMP's forecast of total-company NPC by $13,134,638, or approximately $2,500,000 on a Wyoming allocated basis.[12] However, that seemingly modest net change disguises the fact that the July Update decreased certain costs by $355,165,050 and then offered offsetting increased costs in the amount of $342,030,412. I will discuss these different and offsetting elements in further detail below.

**Q. WHAT WAS THE RESULT OF UPDATING THE FORWARD PRICE CURVE ON A STANDALONE BASIS?**

A. Updating to the June 30, 2023, OFPC resulted in a $114,984,587 total-company reduction to RMP's forecast.[13] Further, RMP incorporated an update for the final EPA Ozone Transport rules which further reduced the forecast by $164,505,558 on a total-company basis.[14] Collectively, the impact of these two items alone reduced RMP's forecast by $279,490,145 on a total-company basis.

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[11] *See In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electric Utility Service Rates in Wyoming of $70,918,825 per Annum or an Average Overall Increase of 13.7 Percent*, Docket No. 20000-352-ER-09 (Record No. 12310), Memorandum Opinion, Findings and Order Approving Stipulation, Appendix A, Attachment C at ¶¶ (A)(3)(f) & (B)(2) (July 29, 2010).
[12] *See* Supplemental Direct Testimony of Ramon Mitchell, RMP Exhibit 10.6.
[13] *Id.*
[14] *Id.* (representing the sum total of the Ozone Transport Rule NOx Allowance Aggregation and Ozone Transport Rule NOx Allowances updates).

**Q. GIVEN THE MAGNITUDE OF THE OFPC AND OZONE TRANSPORT RULE UPDATES, WHY WAS THE IMPACT OF THE JULY UPDATE ONLY $13,134,638?**

A. While the OFPC and Ozone Transport Rule updates produced a significant downward impact, they did not represent the total corrections and updates in the July Update. The total corrections and updates that RMP calculated in its July Update represented a total-company forecast reduction of $177,317,585 to NPC.[15] The magnitude of this downward adjustment, however, is almost entirely undone by an after-the-fact adjustment of $164,182,948 in what the Company refers to as "System balancing impact of adjustments." No testimony or analysis was provided to describe this System Balancing Adjustment, nor what it represents. No explanation was provided as to why it had such a significant impact on the forecast.

In addition, RMP further mitigated the reduction of the OFPC and Ozone Transport Rule updates by incorporating a handful of new modeling methods and changes that increased NPC. This included the modeling changes referred to as the "DA/RT Volume Component," and the "Contingency Reserves for Non-Owned Generation." These new modeling changes offset what would have otherwise been a major reduction to the forecast based on market conditions.

[15] *Id.*

**A. <u>Coal Cost Update</u>**

**Q. WHAT IS THE $164,182,948 SYSTEM BALANCING ADJUSTMENT?**

A. Based on my review, the System Balancing Adjustment simply represents the difference between the final NPC forecast presented in the July Update and the sum of the estimated impacts of each of the individual adjustments RMP documented in Supplemental Direct Testimony. Based on my analysis and as discussed further below, it appears as though the adjustment is as large as it is due to the way the model calculates the stand-alone impact of the various updates and corrections and, most importantly, an error in how the Company estimated the impact of the coal adjustment. Given the magnitude of this largely unexplained adjustment, the utility certainly must adequately explain and defend these amounts as reasonable estimates of net power costs prior to their inclusion in rates.

More specifically, in Supplemental Direct Testimony, RMP documented total-company updates and corrections of $177,317,585.[16] This implied a total-company final NPC forecast of $2,363,033,451.[17] Yet, the final NPC model run RMP performed produced a total-company forecast of $2,540,351,036.[18] Accordingly, to force its request in this case to match its final modeling run, RMP applied a $164,182,948 upward adjustment at the end of its comparison to account for the unexplained variance that it called a System Balancing Adjustment. In other words, the System Balancing Adjustment is a plug figure that RMP added into its July Update forecast to account for the fact that the sum of the individual

[16] *Id.*
[17] *Id.*
[18] *Id.*

adjustments RMP documented in Supplemental Direct Testimony do not produce the same level of NPC as the final July Update forecast. It represents the unexplained variance between the NPC that RMP presented in its initial filing and the NPC it included in the July Update.

**Q. IS AN UNEXPLAINED VARIANCE OF THAT MAGNITUDE EXPECTED?**

A. No. The System Balancing Adjustment offsets 92.6% of the reductions to the NPC forecast that RMP documented in the July Update. An unexplained variance of such a magnitude raises a serious red flag. Because the documented changes do not result in the same NPC as the final July Update forecast, it means one of two things: 1) that the individual adjustments documented in Supplemental Direct Testimony were inaccurate; or, 2) that there were other changes made in the NPC forecast that were not documented in Supplemental Direct Testimony. At a bare minimum, a thorough investigation of the cause of an unexplained variance of such a magnitude would be warranted, along with a discussion of the variance in testimony. RMP, however, did not do that.

**Q. HAVE YOU INVESTIGATED THE CAUSE OF THE LARGE SYSTEM BALANCING ADJUSTMENT?**

A. Yes. Based on my model runs, most of the System Balancing Adjustment has to do with undocumented changes to coal costs included in the final, July Update forecast. In Supplemental Direct Testimony, RMP represents that the impact associated with its coal cost update was a total-company reduction of $6,540,170.[19]

[19] *Id.*

That value, however, was inaccurate. The Supplemental Direct Testimony includes just one sentence on coal costs, stating generically that "[t]he Company updated coal fuel assumptions to reflect changes in prices, volumes and coal supply limitations in the state of Utah." Based on my review of the modeling RMP materially misrepresented the impact of the coal supply update and the associated changes to coal costs that were included in the July Update, which contributed to the unexplained variance included in the System Balancing Adjustment.

**Q. WHAT WAS THE IMPACT OF THE COAL COST UPDATE IN YOUR MODEL RUNS?**

A. My model runs showed that, relative to the initial filing, the coal cost update increased RMP's NPC forecast by $115,225,600 on a total-company basis—not $6,540,170 as presented in the Company's Update filing.[20] Thus, RMP materially misstated the impact of the coal supply update it included in the July Update.

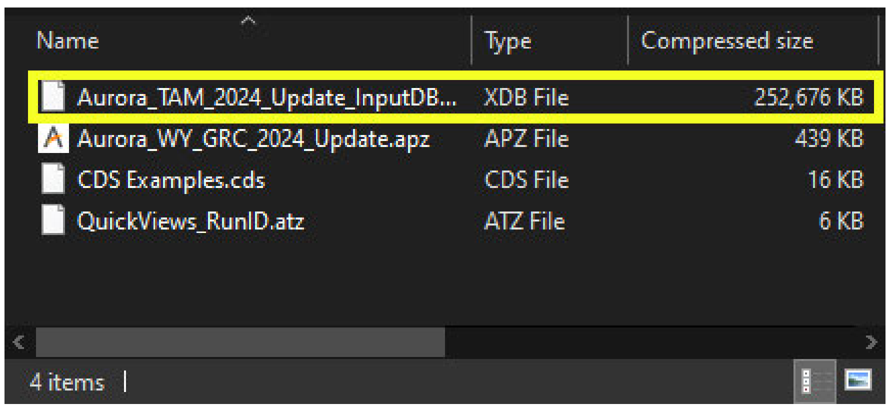
**Q. WHY DID RMP MATERIALLY UNDERSTATE THE IMPACT OF THE COAL COST UPDATE?**

A. When RMP calculated the impact of the coal cost update, it completed a comparison against a scenario that used different coal costs than were included in its initial filing. In other words, RMP's results were fictitious because it was not comparing back to the initial filing. Based on the little documentation provided by the Company, RMP might have compared its coal cost update to the coal costs from the Oregon Transition Adjustment Mechanism ("TAM"), since RMP actually used

[20] Coal costs were included inside the AURORA model in the "Resources Table." To perform my calculation, I reran the July Update using the coal costs that were included in the equivalent Resources Table from the AURORA model submitted with the initial filing.

the AURORA project submitted in the Oregon TAM as the starting point for the July Update, rather than the AURORA model submitted in RMP's initial filing in this case. RMP filed Rebuttal Testimony in the TAM on July 24, 2023, the same day as the July Update, and based on the file names, appears to have used the same AURORA model in both filings. The file names of the AURORA project file submitted in this docket are detailed in **Figure BGM-4**, below.

**Figure BGM-4**
July Update AURORA File Names




Whatever the reason for the misstatement may be, by not comparing back to the originally filed coal costs in this case, the impact of the coal supply update RMP discussed in Supplemental Direct Testimony was not portrayed accurately. Again, when I compare the originally filed coal costs in my model to the level of coal costs in the July Update, it produces a result that is $108,685,430 different than what RMP calculated.

**Q. WHAT IS THE IMPACT ON THE SYSTEM BALANCING ADJUSTMENT BASED ON YOUR RECALCULATION OF THE IMPACT OF THE COAL ADJUSTMENT?**

A. Based on my recalculation of the impacts of the coal adjustment and reflecting the full impact of that adjustment, the resulting System Balancing Adjustment is still $48,957,348. While the Company did not specifically discuss why that adjustment exists, it is possible that the remaining amount is due to other undocumented adjustments or to the cumulative impact of the adjustments not captured in the analysis of the impacts of each individual adjustment.

**Q. REGARDLESS OF THE SIZE OF THE COAL ADJUSTMENT, WHY WERE COAL COSTS UPDATED?**

A. It is unknown. RMP did not support the changes to its coal supply costs in its Supplemental Direct Testimony supporting its NPC Update. Therefore, the changes that were made in the July Update and the reasons for making those changes are unknown.

**Q. DID RMP SUBMIT ANY COAL SUPPLY COST WORKPAPERS WITH THE JULY UPDATE?**

A. No. While RMP submitted coal supply workpapers in its initial filing, no updated coal supply cost workpapers were provided with the July Update. Following receipt of the July Update, WIEC immediately submitted discovery requesting further information on the coal supply update; however, no workpapers were provided.[21]

[21] WIEC Exhibit No. 202.4 (RMP Response to WIEC DR 18.1).

**Q. IS RMP REQUIRED TO SUBMIT WORKPAPERS SUPPORTING ITS COAL COSTS IN NPC FILINGS?**

A. Yes. In Docket No. 20000-352-ER-09, the Commission approved a Stipulation that, among other things, required RMP to submit certain workpapers supporting its NPC filings. This included "Regulatory Fuel Budget and any other workpapers used in developing the power cost model fuel cost inputs."[22] As noted, while RMP complied with this requirement for its initial filing, it did not do so for the July Update.

**Q. WERE YOU ABLE TO DETERMINE WHY THE COAL SUPPLY COST UPDATE WAS SO LARGE THROUGH DISCOVERY?**

A. In WIEC Data Request 18.1, RMP was requested to document each of the changes to coal supply costs, but responded with a single, high level sentence like the one it provided in Supplemental Direct Testimony.[23]

**Q. BASED ON THE FOREGOING, HOW HAVE YOU CONSIDERED THE COAL COSTS IN YOUR FORECAST?**

A. In my forecast, I used the coal costs RMP submitted with its initial filing. Other than a cursory sentence, RMP did not describe or explain the changes that were made to coal costs in its Supplemental Direct Testimony. This is particularly troubling given the magnitude of this adjustment when that magnitude is properly calculated. RMP also did not submit the requisite workpapers required pursuant to

[22] *See In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electric Utility Service Rates in Wyoming of $70,918,825 per Annum or an Average Overall Increase of 13.7 Percent*, Docket No. 20000-352-ER-09 (Record No. 12310), Memorandum Opinion, Findings and Order Approving Stipulation, Appendix A, Attachment C at ¶ 3(f) (July 29, 2010).
[23] WIEC Exhibit No. 202.4 (RMP Response to WIEC DR 18.1).

the Commission's Order in Docket No. 20000-352-ER-09. Considering these facts, neither WIEC nor the Commission has a basis to evaluate or consider the reasonableness of the coal costs included in AURORA in the July Update.

**Q. IS THERE REASON FOR THE COMMISSION TO BE CONCERNED ABOUT THE REMAINING SYSTEM BALANCING ADJUSTMENT?**

A. Yes. Regardless of the size of the System Balancing Adjustment, to the extent that PacifiCorp cannot explain or quantify why the modeled net power costs are changing, it is impossible for intervenors to evaluate or the Commission to decide that those costs are just and reasonable and should be included in rates.

**B. <u>Other Unsupported Modeling Changes</u>**

**Q. DID RMP'S UPDATE INCLUDE OTHER MODELING CHANGES THAT WERE NOT ADEQUATELY SUPPORTED?**

A. Yes. RMP's update filing included two modeling changes, which were not properly supported, including the "DA/RT Volume Component" change and the "Contingency Reserves for Non-Owned Generation" change. It was WIEC's understanding that the new modeling method changes would not be introduced in the July Update, particularly given the limited time available for parties to review the update. While RMP identified these changes as corrections, that was not so. They represented a change in method—a change in the way that the forecasting techniques were being performed. Parties have been reviewing the forecasting for several months, so making material and significant changes such as these at such a late juncture in the proceeding is not appropriate. Collectively, these two modeling changes offset $128,795,265 of the total-company reduction to RMP's NPC forecast that would have otherwise occurred even considering the undocumented change to coal costs above.

**Q. WHAT WAS THE ITEM TITLED DA/RT VOLUME COMPONENT?**

A. This item increased RMP's NPC forecast by $65,812,659. From Supplemental Direct Testimony, it is unclear what this amount represents. RMP makes vague statements such as "[t]he Company corrected an error in the DA/RT adjustment by removing unsupported artificial arbitrage revenue ('artificial gains') from the DA/RT volume component," and "[t]he arbitrage revenue present in the initial filing was above the levels supported by the historical data and showed a substantial and illogical decrease to power costs resulting from inefficiencies in actual power trading, as compared to the actual increase in power costs that results from inefficiencies in actual power trading."[24] From these statements, it is not clear what RMP meant when it used terms such as "artificial arbitrage revenues." It is also unclear how the filed method resulted in an "illogical decrease to power costs resulting from inefficiencies in actual power trading." No information regarding the inefficiencies in actual power trading were submitted to support this claim, nor the significant increase to NPC that resulted from this change.

**Q. WAS THE CHANGE TO THE DA/RT METHOD A CORRECTION?**

A. No. The change was not the result of a formula error or a ministerial error. The change modified the technique that was used to perform the DA/RT method, and therefore, was not accurately characterized as a correction. The modeling change

[24] Supplemental Direct Testimony of Ramon Mitchell, p. 6, lines 14-22.

appears to have introduced an entirely new element into the historically controversial DA/RT adjustment, supported by only a few conclusory statements. This modeling change was not supported in RMP's initial filing, and therefore, was not reasonable to include in the July Update. I therefore recommend the Commission reject this inappropriate modeling change.

**Q. WHAT WAS THE CHANGE RELATED TO CONTINGENCY RESERVES FOR NON-OWNED GENERATION?**

A. RMP states that it corrected a "formulaic error in the calculation of megawatt-hours generated in the PacifiCorp East and PacifiCorp West balancing authority areas by third-party (non-owned) generation."[25] The impact of the change was a $62,982,606 increase to RMP's NPC forecast. This change is also problematic and raises a red flag. First, this level of costs for contingency reserves for non-owned generation is excessive. RMP only collects about $5,761,461 in contingency reserve revenues, including revenues from both non-native loads and non-owned generation resources.[26] Accordingly, a cost of over 10 times that amount for providing contingency reserves to just third-party generators is on its face inaccurate. This adjustment also changed the way that third-party generation was being included in the model. These reserves *were* included in the original modeling, albeit RMP changed the values in AURORA with no support or documentation. As I discuss below, I have modified the way that reserves for third-party generation are included in NPC to be consistent with the way that the FERC

[25] *Id.* at p. 6, lines 7-13.
[26] *See* Workpaper of RMP Witness Highsmith "3.3 Wheeling Revenue," Tab "3.3.1" Cells "K91" and "T91."

handles these costs. Therefore, I recommend the Commission reject this unsupported and, once my recommended correction is done, unnecessary adjustment.

## IV. MODELING DISCUSSION

**Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. I discuss various modeling assumptions and methods that I used to develop my forecast of NPC, as well as differences between my analysis and RMP's. I also discuss certain elements of the forecast which are not appropriately included in Wyoming customer rates.

### A. Aurora Model Environment

**Q. DOES THE AURORA MODEL PRODUCE THE SAME RESULTS WHEN RUN ON DIFFERENT COMPUTER ARCHITECTURES?**

A. No. Depending on the computer architecture (*i.e.*, the computer processor) used to run the model, AURORA will produce slightly different results. Different hardware utilizes different levels of precision and rounding points. Different randomization techniques, which are commonly used in optimization algorithms, may also lead to different results. While these differences are small, they can add up over the course of a large simulation. When I run RMP's July Update on my computer architecture, for example, the AURORA model produces an NPC forecast that is $2,094,119 lower than RMP's forecast on a total-company basis, which I have documented in **Table BGM-1** of my introduction.

**Q. IS IT APPROPRIATE FOR THE COMMISSION TO CONSIDER THIS LEVEL OF IMPRECISION WHEN REVIEWING THE FORECAST?**

A. When setting the approved level of NPC it is appropriate for the Commission to understand that there is a degree of imprecision in the AURORA model dispatch. The level of optimization achieved on my computer architecture was slightly greater than on RMP's. The slightly lower cost was driven by slightly more efficient plant dispatch than produced in RMP's modeling. Therefore, my model runs can be viewed as producing a more accurate forecast. Using my computer architecture reduces total-company NPC by $2,094,140 and $287,935 on a Wyoming-allocated basis.

### B. Washington Climate Commitment Act

**Q. WHAT IS THE WASHINGTON CLIMATE COMMITMENT ACT?**

A. The Washington CCA was passed by the Washington State Legislature in 2021.[27] Among other things, the CCA required the Washington Department of Ecology ("Ecology") to adopt rules establishing a "cap and invest" program. Accordingly, Ecology adopted CCA rules in September 2022 that went into effect on January 1, 2023.[28] The cap in invest program requires certain covered entities to purchase greenhouse gas allowances in connection with carbon emissions from emitting resources. Each allowance covers one Metric Ton of CO2 ("MTCO2") emissions.

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[27] *See* Washington State 67th Legislature, 2021 Regular Session, *Engrossed Second Substitute Senate Bill 5126*, § 8 (2021). *See also* Revised Code of Washington ("RCW") 70A.65, et seq.
[28] Washington Administrative Code ("WAC"), Chapter 173-446, et seq.

**Q. HOW DOES THE CCA CAP AND INVEST PROGRAM WORK?**

A. With some exceptions, stationary sources of greenhouse gasses are required to purchase and retire CCA allowances to offset greenhouse gas emissions.

**Q. HOW DO COVERED ENTITIES PURCHASE ALLOWANCES?**

A. The allowances are auctioned in a quarterly auction process overseen by Ecology. Further, secondary markets are expected to be developed, through which covered entities can trade allowances, although no such markets exist today. In addition, certain covered entities, such as Washington State electric utilities, including the Company, are awarded free allowances to cover *the Washington portion* of the utility's CCA obligations.

**Q. ARE ANY OF THE COMPANY'S RESOURCES COVERED UNDER THE CCA?**

A. Yes. The Washington CCA applies to all emissions produced from generation resources located within the State of Washington,[29] which includes Wyoming's allocated share of the Company's Chehalis natural gas generation facility.

**Q. WHAT IS THE CHEHALIS POWER PLANT?**

A. Chehalis is an approximate 520 MW gas fired generating resource located near Chehalis, Washington along the I-5 corridor about halfway between Portland, Oregon and Seattle, Washington. Chehalis has been included in Wyoming rates since around 2008 pursuant to the terms of the Multi-State Protocol ("MSP") agreements that have been effective over that time.

[29] RCW 70A.65.010(38), 70A.65.080

**Q. HOW IS CHEHALIS TREATED IN THE CCA?**

A. Electric generating facilities, such as Chehalis, must purchase and retire allowances covering 100% of greenhouse gas emissions. However, to reduce the burden of the costs of such allowances to Washington ratepayers, Ecology allocates free allowances to Washington retail electric service utilities to cover their compliance obligations associated with their Washington retail load.[30] In other words, the Company is provided free allowances to cover Chehalis' emissions for the benefit of Washington State ratepayers, while out-of-state ratepayers, such as Wyoming customers, must pay the entirety of the allowance costs. Put another way, this is effectively a Washington-imposed tax that Washington has exempted itself from; only RMP's out of state ratepayers pay this tax.

**Q. HOW MUCH DO CCA ALLOWANCES COST?**

A. So far, two CCA allowance auctions have taken place. The first auction occurred on February 28, 2023, and resulted in an allowance price of $48.50/MTCO2.[31] Total revenues generated from the first auction was $299,983,267. The second auction occurred on May 31, 2023, and resulted in an allowance price of $56.01/MTCO2. Total revenues generated from the second auction were $557,089,850.[32] Based on these results, Washington is on track to generate

[30] RCW 70A.65.120, (4).
[31] Ecology, Washington Cap-and-Invest Program Auction #1 February 2023 Public Proceeds Report (Mar. 7, 2023). Available at https://apps.ecology.wa.gov/publications/documents/2302022.pdf.
[32] Ecology, Washington Cap-and-Invest Program Auction #2 May 2023 Public Proceeds Report (Jun 28,2023). Available at https://apps.ecology.wa.gov/publications/documents/2302058.pdf.

proceeds of approximately $1,971,252,817 in the first year of the CCA's operation.[33] The next auction will occur on August 31, 2023.

**Q. HOW ARE THE FUNDS USED?**

A. The funds are distributed in a special account and are made available to the legislature. There are restrictions on the use of some of the funds, although the majority can be used at the discretion of the legislature. Approximately, 75% of the funds must be distributed into the Climate Commitment Account, which must be used for programs "physically located in Washington state," including funding programs related to the working families tax rebate, making loans to local governments, advancing renewable resource development, financing technical education in colleges and higher education, and other similar investments.[34] Like Wyoming, Washington does not have a general income tax.[35] Washington has had budget shortfalls in recent years, and the while the separate appropriations account has been established for the funds, the CCA account monies—including monies collected from out-of-state customers as the Company is proposing in this proceeding—may alleviate some of those shortfalls.

**Q. HOW MUCH CCA COST DID RMP INCLUDE IN ITS NPC FORECAST?**

A. In AURORA, RMP has modeled a requirement to purchase CCA allowances as an addition to the fuel cost for the Chehalis gas-fired generating facility. Relative to

[33] Based on an assumption that the third and fourth quarter auctions generate the same level of revenues as the second quarter auction. Calculated as $299,983,267 + 3 × $557,089,850.
[34] RCW 70A.65.260.
[35] *See* State of Washington, Climate Commitment Act Funds, Governor's Proposed 2023-25 Omnibus Operating, Capital and Transportation Budget. Available at https://ofm.wa.gov/sites/default/files/public/budget/statebudget/highlights/budget23/CCA-Accounts-summary.pdf.

my forecast, the impact of this assumption was a $69,523,712 increase to NPC on a total-company basis, with approximately $9,559,205 of the increase allocated to Wyoming customers. This impact includes both the cost of allowances, as well as the cost associated with a less efficient generation profile from the Chehalis power plant. On a total-company basis, the cost of allowances contributed to $59,719,477 of the forecast cost, while the cost of uneconomic dispatch contributed to $9,804,235.

**Q. HOW DID THE MODELED ALLOWANCES IMPACT THE COST OF CHEHALIS?**

A. In AURORA, RMP modeled the Washington CCA as a $[redacted]/MWh increase to the cost of fuel from Chehalis resulting in a total fuel cost of $[redacted]/MWh. Absent the CCA, fuel cost of Chehalis would otherwise be $[redacted]/MWh. Thus, the Washington CCA increases the fuel cost of Chehalis by [redacted]%.

**Q. HOW DOES THIS COST COMPARE TO THE WYOMING WIND TAX?**

A. For comparison purposes, the additional cost forecast for Chehalis in connection with the CCA is an order of magnitude higher than the $1.00/MWh Wyoming wind tax. And, of course, the Wyoming tax is paid by all the Company's customers, including customers in Wyoming.

**Q. HOW IS RMP REQUIRED TO ACCOUNT FOR CCA ALLOWANCES?**

A. Environmental allowances are treated as an inventoriable item in FERC Account 158.1 - Allowance Inventory and expensed to FERC Account 509 - Allowances.[36]

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[36] Uniform System of Accounts Prescribed For Public Utilities And Licensees Subject to The Provisions of The Federal Power Act, 18 CFR 101.

Environmental allowances have been expensed to FERC Account 509 since 1993,[37] although the account language formerly referenced sulfur dioxide allowances and was recently modified to be more generic, removing the reference to sulfur dioxide and adding new sub accounts related to renewable energy certificates, which are also recorded to FERC Account 509.[38]

**Q. DID RMP FOLLOW THE APPROVED FERC ACCOUNTING IN THIS DOCKET?**

A. No. RMP included the cost of CCA allowances as a cost of fuel for Chehalis in FERC Account 447- Fuel.[39] This accounting resulted in the inclusion of the CCA allowances in NPC, as well as in the Schedule 95 Energy Cost Adjustment Mechanism ("ECAM") Base. This accounting, however, is not in compliance with FERC requirements since CCA allowances must be expensed to FERC Account 509 - Allowances, not to FERC Account 447 - Fuel.

**Q. IS FERC ACCOUNT 509 – ALLOWANCES A PART OF NPC OR THE ECAM?**

A. No. RMP has not proposed any modification to Schedule 95 to include FERC Account 509 in NPC.[40] Therefore, accounting for the CCA allowances as a fuel cost and in the ECAM Base was improper accounting.

[37] *See Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A*, FERC Order 552, 62 FERC ¶ 61,299 (Mar. 31, 1993).
[38] *See Acct. & Reporting Treatment of Certain, Renewable Energy Assets*, 180 FERC ¶ 61,050 (July 28, 2022).
[39] *See* Direct Testimony of Nicholas Highsmith, RMP Exhibit 11.2, p. 95 (Line "Natural Gas Consumed": Column "6").
[40] *See* Direct Testimony of Robert Meredith, RMP Exhibit 12.10, p. 23-29.

**Q. IN SHORT, WHAT IS THE PRACTICAL IMPACT ON WYOMING RATEPAYERS IF THE COMMISSION WERE TO APPROVE THE INCLUSION OF THE WASHINGTON CCA COSTS IN RMP'S REVENUE REQUIREMENT?**

A. The practical impact is that Wyoming ratepayers would be funding Washington's local programs aimed related to the working families tax rebate, making loans to local governments, advancing renewable resource development, financing technical education in colleges and higher education, and other similar investments, even though RMP's Washington ratepayers, who have exempted themselves, are not doing the same.

**Q. PLEASE FURTHER EXPLAIN THE DISCRIMINATORY IMPACT OF THE CCA ALLOWANCE COSTS.**

A. As stated above, a key provision of the Washington CCA is that it provides no-cost allowances to electric service companies to offset the "cost burden" of complying with the CCA for only their Washington ratepayers. The cost burden of the program is calculated by Ecology using Washington, utility-specific demand and supply forecasts. These no-cost allowances are detailed in responses to WIEC Data Request 6.11 through 6.15.[41] As can be seen, the Company is expected to receive 7,699,149 in no-cost allowances over the period 2023-2026. Based on the most recent auction price, that volume of free allowances amounts to a $431,229,335 benefit provided to only the Company's Washington customers, which is not

[41] WIEC Exhibit No. 202.4 (RMP Resp. to WIEC DRs 6.11 – 6.15).

equally provided to Wyoming customers. No-cost allowances are not provided to electric service companies for the cost burden of compliance for retail service provided outside of Washington and if RMP's forecast is adopted, RMP's Wyoming customers would be paying CCA compliance costs that are not equally applicable to RMP's Washington customers.

**Q. IS IT REASONABLE FOR WYOMING CUSTOMERS TO PAY THE COST OF WASHINGTON STATE POLICY?**

A. No. A fundamental principle of interjurisdictional cost allocation established in the MSP is that states' policy decisions should not impact the costs allocated to other states. For example, the cost of purchasing renewable energy certificates to satisfy the renewable portfolio standards of individual states has historically been situs assigned to the states' imposing such standards.

**Q. DOES THE COMPANY SET RATES FOR SERVICE IN WASHINGTON BASED ON THE 2020 PROTOCOL?**

A. No. Historically, Washington has not participated in the MSP interjurisdictional allocation agreements and has adopted its own allocation framework that focuses on resources located in RMP's Western balancing area. While Washington became a signatory to the 2020 Protocol, the 2020 Protocol methodology generally is not used to set rates in Washington. Rather, Washington uses a separate allocation framework referred to as the Washington Inter-Jurisdictional Allocation Methodology ("WIJAM") identified in Appendix F to the 2020 Protocol. Thus, the cost allocation framework applied in the 2020 Protocol do not necessarily apply to costs initiated by Washington State.

**Q. DOES THE 2020 PROTOCOL OTHERWISE SPECIFY HOW THE CCA COSTS ARE TO BE ALLOCATED?**

A. No. The CCA allowance costs at issue in this proceeding are not described within the 2020 Protocol. Given their nature and magnitude, for example, I do not believe that they are accurately described as a generation tax under Section 3.1.7, for example. Under the MSP the costs associated with state-specific policy initiatives are typically situs assigned, although given that Washington does not participate in the 2020 Protocol allocation framework, which would establish such situs assignment, there is nothing in the 2020 Protocol that dictates how to allocate costs such as those incurred for CCA compliance. Given this ambiguity, I believe the Commission has latitude to evaluate the issue and adopt whatever approach that it finds to be most reasonable.

**Q. DO THE DIFFERENT ALLOCATION METHODS BETWEEN WASHINGTON AND OTHER STATES RESULT IN RMP OVER RECOVERING THE COST OF CHEHALIS?**

A. Yes. Under the WIJAM method, Washington is allocated approximately 19.9% of the cost of Chehalis. Under the 2020 Protocol, however, the remaining states are allocated 95.5% of the cost of Chehalis. As a result of the different allocation methods, RMP recovers 115.4% of the cost of Chehalis between its six jurisdictions.

**Q. DOES THIS MEAN THAT RMP'S FORECAST ALSO OVERSTATES THE COST OF CCA COMPLIANCE?**

A. Yes. After considering the free allowances provided for Washington's 19.9% share of Chehalis, RMP's forecast assumes that it will need to acquire allowances on behalf of other states based on 95.5% of the output of Chehalis, resulting in allowance costs covering 115.4% of Chehalis. Thus, after considering the different allocation methods and the free allowances provided to Washington customers, RMP's CCA allowance proposal would otherwise result in a windfall to the Company by overstating its actual cost of CCA compliance.

**Q. IS THE CCA THE SUBJECT OF LEGAL CHALLENGE?**

A. Yes. On December 13, 2022, Invenergy, an Independent Power Producer that operates in the State of Washington, filed a lawsuit in United States District Court seeking a declaratory ruling and injunctive relief regarding the CCA, stating that "[t]he CCA's allocation of no-cost allowances, therefore, violates the Constitution [because it]…impermissibly discriminates against out-of-state business in violation of the dormant Commerce Clause".[42]

**Q. IS RMP SIMILARLY CHALLENGING THE APPLICABILITY OF CCA ON BEHALF OF WYOMING CUSTOMERS?**

A. No. RMP has an obligation to act in the interest of its Wyoming customers, and while the interests of its differently situated customers in different states can create a complex dynamic, that does absolve it of its obligations to Wyoming customers.

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[42] *Invenergy Thermal LLC v. Watson*, Case No. 3:22-cv-5967-BHS, Complaint for Declaratory and Injunctive Relief, ¶ 15 (W.D. Wash. filed Dec. 13, 2022).

**Q. HOW HAVE YOU ADDRESSED THE WASHINGTON CCA COSTS IN YOUR FORECAST?**

A. Given the foregoing, I have removed the CCA allowance costs from the Chehalis dispatch costs in my NPC forecast. This adjustment reduces total company NPC by $69,523,712 and $9,559,205 on a Wyoming-allocated basis.

### C. Day-Ahead / Real-Time Method

**Q. WHAT IS THE DA/RT MODELING METHOD?**

A. The DA/RT method was a modeling technique RMP introduced into the GRID model in Docket No. 20000-469-ER-15, (the "2015 GRC").[43] The method adjusts the cost of purchases and sales relative to average monthly prices used in the OFPC. Part of the justification for the technique was that the hourly prices used in the GRID model were derived from monthly averages and the GRID model was transacting at prices that were more optimal than historical averages.[44] This was described by the Commission in the 2015 GRC as follows:

> RMP proposed to change the way it models day-ahead and real-time balancing transactions. In the real-time market, RMP must transact to maintain a balanced system. As a result, RMP becomes a price taker subject to whatever price is available at the time. The volume of system balancing transactions generated by GRID is smaller than the volume of similar transactions in actual results. Because GRID balances the Company's load and resources to fractions of a MW for each hour in a single step it avoids the additional purchase and sale transactions that occur in actual operations as the Company

[43] *See In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent*, Docket No. 20000-469-ER-15 (Record No. 10476), Direct Testimony of Gregory N. Duvall.
[44] *Id.* at p. 28, lines 3-12

> progresses through balancing its system on a monthly, daily, and real-time system basis.[45]

**Q. HOW WAS THE DA/RT METHOD PERFORMED?**

A. The actual mechanics of the DA/RT method were complicated, including both adjustments to the hourly market prices input into the GRID model, as well as a spreadsheet adjustment made outside of the GRID model after the simulation is performed.

**Q. HOW WAS THE DA/RT METHOD APPLIED WITHIN THE GRID MODEL?**

A. First, RMP modeled a price spread between hourly sales and purchase prices in the GRID model.[46] This made the cost of purchases more expensive and reduced the revenues from wholesale sales. The intention of this change was to produce results that aligned with historical transaction patterns. This first step is sometimes referred to as the "price adjustment" of the modeling method.

**Q. WHAT WAS THE SPREADSHEET ADJUSTMENT?**

A. In GRID, the modeled transaction after incorporating the price spreads still produced results that were more optimal than the historical transaction pattern. Accordingly, RMP applied a second adjustment outside of the GRID model that tied the overall model impact to the historical impact of the DA/RT adjustment, as

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[45] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent*, Docket No. 20000-469-ER-15(Record No. 10476), Memorandum Opinion, Findings of Fact, Decision and Order, ¶ 44(vi) (Dec. 30, 2015).

[46] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent*, Docket No. 20000-469-ER-15 (Record No. 10476), Direct Testimony of Gregory N. Duvall, p. 31, lines 21-19.

calculated over a four-year period.[47] As RMP explained, the purpose of this second adjustment was to ensure that "the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices [was] equal to the historical average."[48] Effectively, this step served as a plug, which tied the DA/RT impacts back to the historical DA/RT levels. With this second step, the first step became perfunctory, except to the extent that it modified the way thermal plants were dispatched. In this second step, RMP also added additional sales and purchase volumes into NPC, although the net impact of these volumes on NPC was zero; they were directly offsetting and produce no impact on NPC. RMP refers to this second, spreadsheet adjustment as the "volume adjustment," although that is a misnomer, because it relates more to tying the results back to the historical DA/RT transaction patterns. Accordingly, for purposes of this testimony, I refer to the spreadsheet adjustment as the "historical adjustment."

**Q. DID RMP APPLY A MODELING METHOD SIMILAR TO THE DA/RT MODELING TECHNIQUE IN AURORA?**

A. Yes. In its initial filing, RMP applied similar modeling, including both the price adjustment to hourly market prices and the historical adjustment tying back to the historical average DA/RT impacts.[49] Notably, RMP made no mention of needing to make wholesale modifications to the DA/RT method in its Direct Testimony,

[47] *Id.*, Rebuttal Testimony of Brian S. Dickman, p. 14, lines 11-14.
[48] *Id.*, Direct Testimony of Gregory N. Duvall, p. 32, lines 8-14.
[49] Direct Testimony of Ramon Mitchell, p. 27, line 7 through p. 28, lines 12.

other than its proposal to model the price adjustment using a percentage rather than a flat value.[50]

**Q. DID RMP MAKE WHOLESALE CHANGES THE WAY IT PERFORMED THE DA/RT METHOD IN ITS JULY UPDATE?**

A. Yes. In its July Update, RMP added an entirely new modeling adjustment to the DA/RT method. After applying the price adjustment and after applying the historical adjustment, RMP made an entirely new, third DA/RT adjustment. This adjustment was another spreadsheet adjustment performed outside of the AURORA model which, in RMP's modeling, resulted in an addition DA/RT cost of $65,812,659 on a total-company basis.[51] When I evaluated it in my forecast, the impact of that adjustment was even larger, equating to $82,828,304 on a total-company basis, which was due to the interrelated impacts of other modeling adjustments I had proposed. To put the magnitude of this change into context, the total NPC impact of the DA/RT adjustment, prior to this third adjustment, was $46,505,169. Thus, this unexplained third adjustment introduced only three weeks before intervenor testimony was due resulted in a near tripling of the overall impact of the DA/RT adjustment.

**Q. DID RMP EXPLAIN WHY IT ADDED THE THIRD DA/RT ADJUSTMENT?**

A. No. Based on the formulas that were used, I was unable to ascertain the purpose of this new dollar adjustment, which was vaguely described in Supplemental Direct

[50] *Id.* at p. 28, lines 21-22
[51] Supplemental Direct Testimony of Ramon Mitchell, RMP Exhibit 10.6.

Testimony as "artificial arbitrage revenue." It appears that RMP may have formulaically eliminated the historical adjustment, albeit in a roundabout way, though this was not readily apparent from the spreadsheets provided. Since this portion of the adjustment was new, and not documented or supported in Supplemental Direct Testimony, I have not considered it in my NPC forecast. In **Table BGM-1** of my Introduction, I have separately detailed the impact of reverting back to the DA/RT method included in RMP's initial filing.

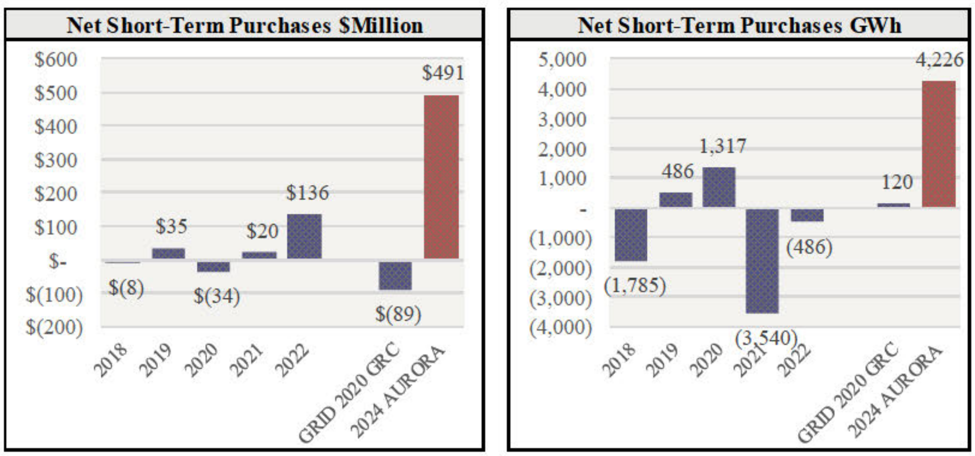
**Q. IS THE DA/RT ADJUSTMENT NECESSARY IN AURORA?**

A Not necessarily. As noted in the quote from the Commission Order in the 2015 GRC, the DA/RT adjustment was implemented to address a shortcoming in the GRID model, which is not necessarily present in the AURORA model. Importantly, the two models use different approaches to calculate dispatch. The GRID model simulated system dispatch using an hourly linear program that calculated transmission-constrained, least-cost dispatch. While less is known about the proprietary algorithms used in AURORA, it is known that the AURORA model dispatch does not contain the same level of transaction optimization as the GRID model did. Unlike GRID, AURORA is based on merit-order dispatch, meaning it simply dispatches the lowest cost resources necessary to meet zonal load requirements. This approach works in a regional dispatch, where there are no external market sales or complex transmission constraints that must be optimized. The approach does not, however, necessarily solve for the absolute optimal level of dispatch necessary for making market purchase and sales transactions in a complex transmission constrained topology, as the GRID model did.

**Q. HOW DO YOU KNOW THAT THE AURORA MODEL IS PRODUCING LESS OPTIMAL DISPATCH RELATIVE TO THE GRID MODEL?**

A. The AURORA model is producing levels of short-term purchase transactions that are inconsistent with historical levels and inconsistent with the levels produced in GRID. AURORA is purchasing more and selling less. In **Figure BGM-5**, below, I provide a comparison of actual net short-term purchases over the period 2018 through 2022 to the levels forecast in RMP's AURORA modeling. I also compare those actual amounts to the forecast prepared in the 2020 GRC.

**Figure BGM-5**
Comparison of Aurora and Historical Net Short Term Purchases




While the levels of net short-term purchases vary year to year both in terms of volumes and cost, it is apparent that the AURORA model is modeling excessive levels of net short-term purchases both in terms of dollars and volumes. The GRID model, for example, produced net short-term sales of 120 GWh in the 2020 GRC; whereas, the AURORA model produced 4,226 GWh. From this, it can be ascertained that the AURORA model is not optimizing short-term sales and purchase transactions at the same level as GRID and in a manner that is less efficient than experienced historically. This historical disconnect is further shown in **Figure BGM-3** in the Background section above. This is an indication that a DA/RT method, as RMP has implemented it, is not necessary for the AURORA model.

**Q. HOW DOES THE AURORA MODEL DISPATCH COMPARE TO HISTORICAL DA/RT IMPACTS?**

A. In **Confidential Figure BGM-6**, below, I compare the historical DA/RT impacts (*i.e.*, the difference between the effective rate for sales and purchases and monthly market prices) to the modeled DA/RT impacts in AURORA, inclusive of the DA/RT method price adjustments, but excluding the second step where the costs are tied to the historical averages. I also compare to the implicit DA/RT impacts, assuming no DA/RT price adjustment is included in AURORA.

**Confidential Figure BGM-6**
Historical DA/RT Impact vs. Initial Filing AURORA
$Millions

[redacted]

In AURORA, the DA/RT price adjustment produced an overall DA/RT adjustment market value of $[redacted]. This, of course, does not consider the $65,812,659 DA/RT method modeling change presented in the July Update, which increases the cost to $[redacted]. This compares to a historical value of $[redacted] over the 48-months ending June 30, 2022. Thus, the impact of the DA/RT adjustment as applied to the market prices in AURORA results in RMP materially overstating its cost relative to the historical average.

**Q. WHAT IS THE DA/RT IMPACT IF THE PRICE ADJUSTMENT IS REMOVED COMPLETELY?**

A. In my modeling, if the DA/RT price adjustment is removed completely, the AURORA model produced an implicit DA/RT adjustment of $[redacted], which is generally in line with the historical data. This means that the AURORA model is already accurately capturing the impact of buying more during high priced hours and selling more during low priced hours and that a DA/RT adjustment is largely unnecessary. In contrast, continuing to use the price adjustment in AURORA is producing a skewed dispatch and inaccurate results.

**Q. HOW HAVE YOU MODELED THE DA/RT ADJUSTMENT IN YOUR FORECAST?**

A. Considering that the price adjustments RMP included in AURORA were producing impacts that were materially greater than the historical averages, I removed the in-model price adjustments from my forecast. Notwithstanding, in order to recognize the slight variance between the historical DA/RT impacts and the implicit modeled

DA/RT impacts, I still retained the historical adjustment in the NPC spreadsheet to tie the modeled impacts back to the $[redacted] historical average. By doing the modeling this way, I avoided all the inconsistent results discussed above, while still capturing the full impact of the DA/RT adjustment. In doing it this way, I also avoided any of the modeling convolutions which might be attributed to the "artificial arbitrage revenues," whatever those may be, that RMP modified in the July Update. Finally, since the out-of-model volumes included in the NPC report were perfunctory, and had no impact on NPC, I also removed those from my modeling.

**Q. HOW DID YOUR MODELING APPROACH IMPACT NPC?**

A. While the end result of the modeling on the DA/RT adjustment tied back to the historical average, it resulted in more accurate thermal plant dispatch, which reduced NPC. As noted in **Table BGM-1** of my introduction this subtle change lowered the NPC forecast by $17,141,121, with $2,356,829 allocated to Wyoming. Note that these impacts do not consider the impact of removing the new spreadsheet adjustment RMP included in its July Update, which I also removed and stated separately in **Table BGM-1**. That adjustment amounts to a reduction to forecast NPC of $80,199,295 on a total-company basis and $ 11,027,051 on a Wyoming-allocated basis.

**D. Market Caps**

**Q. WHAT ARE MARKET CAPS?**

A. Market caps were a modeling parameter programed into the former GRID model to address alleged over-optimization of the model algorithm at certain illiquid market hubs. The parameter established a hard limit on the maximum volume of sales that could be made at a market hub in any hour. The use of market caps in GRID has been a source of modeling controversy since the GRID model was implemented and was one of the justifications for moving to a new model, such as AURORA, to avoid the need for exogenous modeling limitations such as market caps.

**Q. DOES THE AURORA MODEL CONTAIN A MARKET CAP MODELING PARAMETER?**

A. No. The AURORA model contains no specific modeling parameter limiting the volume of off-system sales as GRID did. In fact, the AURORA model lacks capability to evaluate off-system sales altogether; the AURORA model was designed to simulate market prices using regional dispatch, not to develop a closed-system dispatch as GRID was designed to do. It is only by means of complicated modeling workarounds that RMP was even able to incorporate off-system sales, and a closed system dispatch in AURORA. The workaround, which involved displacement of fictionalized loads at each market hub, will not fully be evaluated here, although it is likely that there are issues with it. Nevertheless, when implementing this workaround, RMP limited the volume of fictional loads used to simulate off-system sales included in an AURORA table called "Hub Demand."

This was done with the apparent objective of duplicating market caps, although the approach was subject to unexplained modifications relative to the Commission-approved method for modeling market caps in GRID.

**Q. WHAT MODELING METHOD HAS THE COMMISSION APPROVED FOR MARKET CAPS IN GRID?**

A. Since the implementation of the GRID model, the Commission has approved various modeling methods for market caps. The most recently approved method dates to RMP's 2014 GRC. In that proceeding RMP applied a cap on the hourly level of sales that could be made at certain illiquid markets, which was "based on the four-year average historical short term firm transactions, broken down by market, month and hour class."[52] For each monthly diurnal period, RMP took the average of the average level of sales in the same monthly diurnal period in the four-year history. Thus, the market caps in each monthly diurnal period were calculated based on the average of only four values. For example, as applied to the Test Period, the market cap applicable for heavy-load-hours ("HLH") in June 2024 at Mona would otherwise be based on the average of the average sales made at Mona in HLH of June 2022, HLH of June 2021, and HLH of June 2020 and HLH of June 2019.

**Q. DID MARKET CAPS APPLY TO ALL MARKET HUBS?**

A. No. The approved market cap method was limited only to illiquid market hubs. This assumption was discussed in detail in the Direct Testimony of Gregory N.

[52] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electric Utility Service Rates in Wyoming of $36.1 Million per Year or 5.3 Percent*, Docket No. 20000-446-ER-14 (Record No. 13816), Direct Testimony of Gregory N. Duvall, p. 14, line 22 through p. 15, line 1.

Duvall in the 2014 GRC, where RMP proposed removing market caps for the Mid-Columbia and Palo Verde markets. As RMP witness Duvall stated, "sales restrictions on the Mid-Columbia and Palo Verde markets have been removed."[53] RMP presented several reasons for excluding a market cap limitation on these markets. First, the markets were liquid, with robust forward markets. RMP stated that "markets have many participants and are often used to balance the Company's load and resource position on a forward basis."[54] The level of sales at these markets is also more dependent on the level of its generation, rather than liquidity in the market. RMP witness Duvall stated, "the Company's historical sales at the Mid-Columbia and Palo Verde markets may be more strongly aligned with the Company's resource position, rather than the position of the other counterparties in the market."[55]

**Q. DID RMP APPLY THE SAME METHOD TO THE HUB DEMAND LIMITS IN AURORA?**

A. No. When applying the market cap method in the AURORA hub demands, RMP added back sales restrictions on the liquid markets, including the Mid-Columbia market and the Palo Verde market. Notwithstanding this material change in the Commission-approved method, RMP made no mention of it in Direct Testimony. In fact, RMP does not discuss the market cap or hub demand assumptions at all in its Direct Testimony.

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[53] *Id.* at p. 14, lines 21-22.
[54] *Id.* at p. 19, lines 15-16.
[55] *Id.* at p. 19, lines 17-20.

**Q. HAVE YOU APPLIED A MARKET CAP LIMITATION TO LIQUID MARKETS IN YOUR MODELING?**

A. No. Consistent with the method the Commission approved in the 2015 GRC and all subsequent rate case proceedings, I have removed the market caps limitations from liquid market hubs. For the reasons RMP discussed in the 2014 GRC, there is no reason to apply market caps to those markets. Further, I expanded the definition of liquid markets to include the Mid-Columbia market hub, the Palo Verde market hub, *and* the Four-Corners market hub.

**Q. WHY HAVE YOU INCLUDED THE FOUR-CORNERS MARKET HUB AS A LIQUID MARKET?**

A. As the markets in the West are becoming more developed, the liquidity at any given market point is improving. The forward and bilateral markets at Four-Corners, for example, are more robust than they were nine years ago when RMP first proposed to remove liquid markets from the market cap calculation. Four Corners is now traded on the liquid Intercontinental Exchange platform, with robust forward market pricing.[56] Further, RMP no longer has firm transmission access to the Palo Verde market following the retirement of Cholla Unit 4, and accordingly, is increasingly relying on the Four Corners market to make sales in the Desert Southwest. In 2022, for example, RMP made [redacted] MWh of short-term sales at the Four Corners market, which was [redacted]. In comparison, short-term sales at the Mid-Columbia market in 2022 were [redacted]

[56] *See e.g.*, Intercontinental Exchange, Four Corners 345 Physical Peak (bilateral) Product Specification. Available at https://www.ice.com/products/1067/Four-Corners-345-Physical-Peak-bilateral.

MWh and short-term sales at the Palo Verde market were [redacted] MWh. The relative level of short-term sales transactions indicates that the market liquidity at Four Corners market hub must be at least comparable, if not greater than, the other two market hubs.

**Q. HOW DID THE REMOVAL OF SALES RESTRICTIONS ON THESE LIQUID MARKET HUBS IMPACT YOUR FORECAST?**

A. Relative to RMP's forecast, removal of sales restrictions on liquid market hubs produced a $20,974,080 reduction to my forecast, with approximately $2,883,844 allocated to Wyoming.

**Q. DOES THIS RESULT IN THE AURORA MODEL MAKING UNLIMITED SALES AT THOSE MARKETS?**

A. No. The capacity for AURORA to make sales at any particular market hub is limited by transmission constraints in the model, which is consistent with the constraints that RMP faces in actual operations. The market cap limit on these liquid markets would otherwise reduce the capability to sell at such markets below the transmission limitation to an arbitrarily low level, which is not consistent with RMP's actual ability to make sales at such markets.

**Q. IS IT APPROPRIATE TO USE AN AVERAGE OF AVERAGES TO CALCULATE MARKET DEPTH?**

A. No. By definition, using an average to set a maximum level of sales will result in a level of sales that is less than the historical average. An average of a diverse set of data is always less than the maximum. If the forecast maximum is set at the historical average, the forecast average will by definition come in at less than the forecast maximum and less than historical average. This is a major problem with RMP's use of an average of averages level for market caps. Another problem has to do with the use of a small sample size. RMP's method relies on monthly values over the four-year period. For any particular period, it results in only four values being considered in the summary statistic. A sample size of four data points, however, is not sufficient to form any statistical conclusions about market depth.

**Q. HOW HAVE YOU ADDRESSED MARKET CAPS FOR THE NON-LIQUID MARKETS IN YOUR FORECAST?**

A. To address the issues associated with the small sample size and the use of an average instead of a maximum level, I calculated the 95$^{th}$ percentile level of average monthly sales for both HLH and LLH hours for each market and each month over the 48-month period. Under this approach, I used 48 different values to calculate maximum market capability, which addressed the small sample size issue. I also used a 95$^{th}$ percentile to better calculate the maximum capability for making sales, rather than the average. Based on the value calculated, I applied the same market depth limit for all hours of the year, with a separate cap level for HLH and LLH time periods.

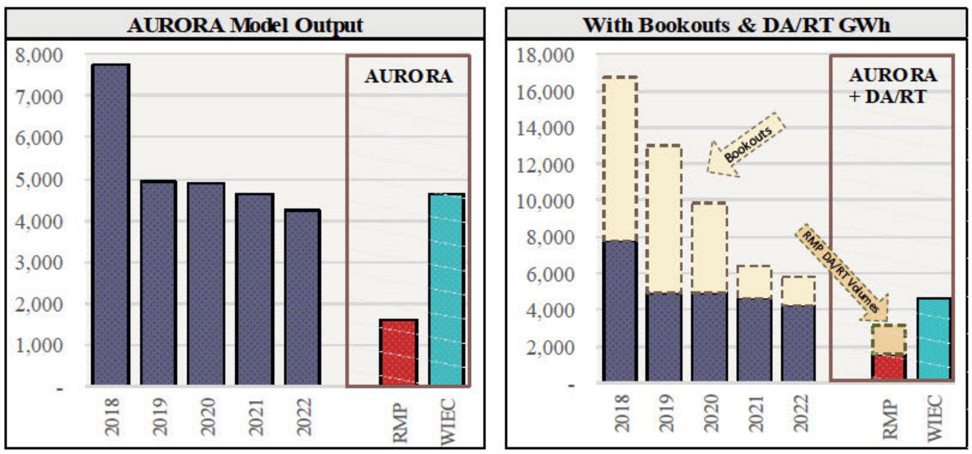
**Q. WHAT IS THE IMPACT OF YOUR METHOD FOR THE NON-LIQUID MARKETS?**

A. Modifying the calculation to be based on a flat 95th percentile level resulted in a further $17,091,156 reduction to my forecast of total-company NPC, with $2,349,959 allocated to Wyoming.

**Q. DOES YOUR METHOD PRODUCE A MORE ACCURATE LEVEL OF WHOLESALE SALES?**

A. Yes. In **Figure BGM-7**, below, I provide a comparison between the sales modeled by the AURORA model, under both my approach and the Company's, and the level of actual wholesale sales made over the five-year period 2018 through 2022.

**Figure BGM-7**
Market Cap Methods vs. Historical Sales Volumes
GWh




As can be seen, my method is clearly more in line with the historical data. While there are a few ways to compare the modeled output of AURORA to historical sales volumes, any valid way the analysis is performed, it shows that RMP's market cap method is materially understating sales volumes relative to historical actuals. The left chart in **Figure BGM-7** is in my opinion the more accurate way to perform the comparison. It compares the level of sales generated directly in the AURORA model to the level of sales included in RMP's actual NPC report. As can be seen, RMP's market cap method results in aurora producing just [redacted] MWh of wholesale sales transactions compared to an average of approximately [redacted] MWh in the historical period. That is a variance of -70%. In contrast, the method that I used resulted in AURORA modeled sales of [redacted] MWh, which is below, but generally in line with the average.

**Q. WHY HAVE YOU ALSO PERFORMED A COMPARISON INCLUDING BOOKOUT TRANSACTIONS?**

A. In actual NPC, there are a large number of transaction volumes that are "booked-out" and are not reported in sales volumes in the actual NPC report. The accounting for these bookout transactions is complicated, but generally, they occur when a simultaneous sale and purchase transaction occur at the same time and at the same market hub. Utilities enter into large volumes of bookout transactions at market hubs, which are reported separately on FERC Form 1. The FERC Rules surrounding bookouts may be found in 18 CFR 35 and I have included a citation to a Federal Register notice that describes the FERC approved treatment.[57]

AURORA, on the other hand, does not explicitly model bookout transactions. AURORA does not model simultaneous sales and purchases at the same market hub. In RMP's DA/RT method, however, it included offsetting sales and purchases as a spreadsheet adjustment, which I discussed above. While bookouts and the DA/RT volumes are not necessarily precisely the same, I prepared a second chart in **Figure BGM-7** that compares the actual historical sales levels with all offsetting transactions, including both bookouts and the offsetting DA/RT volumes. If offsetting transactions are to be considered in the analysis, they need

[57] Filing Requirements for Electric Utility Service Agreements; Electricity Market Transparency; Revisions to Electric Quarterly Report Filing Process; Electric Quarterly Reports, 81 Fed. Reg. 69731 (Oct. 7, 2017).

to be considered on both sides of the comparison. Due to the nature of the DA/RT adjustment, I view that analysis to be a less accurate representation of sales transactions. If the DA/RT volumes are leading to an excessive level of sales, for example, that means that the DA/RT volumes are being overstated, not that the AURORA model is producing inaccurate sales levels. Notwithstanding, even considering the offsetting DA/RT volumes, the analysis still shows that RMP sales are materially understated relative to the historical average. As noted, I did not include any DA/RT volumes in my study, so my results are well below the historical average if bookouts are considered in the historical data.

In other words, however the comparison is performed, it shows that RMP's market cap method, as applied in the AURORA model, is overly restrictive, resulting in sales levels that are too low relative to historical levels. In contrast, my method produces results that are in line with the historical data.

### E. <u>Ozone Transport Rule</u>

**Q. WHAT IS THE OZONE TRANSPORT RULE?**

A. The Ozone Transport Rule was published by the Environmental Protection Agency ("EPA") on June 5, 2023.[58] Among other things, the rules were designed to reduce the amount of ozone-forming emissions of nitrogen oxides transported into neighboring states. Under the rule, electric generators are required to follow specific state implementation plans ("SIP") designed to limit nitrogen oxide emissions. In the recent rule implementation, the EPA issued SIPs for 22 different

[58] EPA, Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg 36654 (June 5, 2023).

states, including Utah. A fact sheet on the program is attached as **WIEC Exhibit 202.5.**

**Q. HOW DID RMP MODEL THE RULE?**

A. In its July Update, RMP applied limits on the generation from coal-fired resources in both Wyoming and Utah. RMP states, "[a]s in the initial filing, the NPC update assumes the [Ozone Transport Rule] applies to both Utah and Wyoming in the Test Period."[59] Notwithstanding, RMP modified its modeling method for the Ozone Transport Rule to be based on a total-company limit on the overall amount of nitrogen oxide emissions from gas and coal facilities in both Wyoming and Utah in the months of May through September. This is in contrast to the initial filing, where RMP had modeled restrictions on a unit-by-unit basis and applied the restrictions in every month of the year.

**Q. IS RMP'S MODELING CONSISTENT WITH THE FINAL RULE?**

A. No. Foremost, Wyoming was not subject to the final rule issued by the EPA. The Federal Register notice states "we are deferring final action at this time on the proposed [Federal Implementation Plans] for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action."[60] The EPA is conducting additional analysis and review of Wyoming's SIP because the EPA's analysis to date suggests that it is uncertain if Wyoming is contributing to air quality problems in amounts sufficient to link them to the downwind air quality problems. EPA stated, "[w]ith respect to

[59] Supplemental Direct Testimony of Ramon Mitchell, p. 7, lines 7-8.
[60] 88 Fed. Reg. 36654, p. 36715-16.

Wyoming, our methodology when applied using the 2016v3 modeling suggests that whether the state is linked is uncertain and warrants further analysis."[61] The EPA deferred its final action on Wyoming's SIP until December 15, 2023.

**Q. IS THE RULE BEING CHALLENGED?**

A. The rules have been challenged and has already been stayed in several jurisdictions, including a stay issued on May 1, 2023 for Texas and Louisiana.[62] On April 5, 2023, Wyoming similarly submitted a lawsuit to the 10th Circuit Court of Appeals to review the decision for deferred action on the Wyoming SIP, since according to EPA's analysis no action was required for Wyoming.[63] Further, a lawsuit was filed by Utah on June 20, 2023 similarly requesting review of the rule.[64] Thus, it is highly unlikely that the rule will be applied to Wyoming in the 2024 ozone season, even if the EPA's efforts for deferred action are successful. And, the likelihood that the new rule will apply to Utah in 2024 is unknown, as it is possible that the implementation plan for Utah will be modified, overturned, or stayed by the pending lawsuit.

**Q. HOW HAVE YOU MODELED THE OZONE TRANSPORT RULE IN YOUR FORECAST?**

A. Given that the Ozone Transport Rule will not apply to Wyoming in the Test Period and the uncertainty surrounding Utah's SIP, I have not considered the Ozone

[61] *Id.* at 36717.
[62] *See Texas v. United States EPA*, No. 23-60069, 2023 U.S. App. LEXIS 13898 (5th Cir. May 1, 2023).
[63] *State of Wyoming v. EPA,* No. 23-9529, (10th Cir. filed Apr. 5, 2023).
[64] *See State of Utah v. United States EPA*, No. 23-1157, Petition for Review (D.C. Cir. filed June 20, 2023). Available at https://attorneygeneral.utah.gov/wp-content/uploads/2023/06/2023-06-20-Utah-DC-Petition-for-Review-of-FIP-1.pdf.

Transport Rule in my NPC forecast. While RMP's modeling in its July update reduced the impact relative to its initial filing, its Ozone Transport Rule modeling continued to produce a material impact on its forecast. Further, the entirety of the impacts was associated with the limits placed on generation resources located in Wyoming. Accordingly, in my modeling, I removed the ozone transport constraint for Wyoming resources only, which reduced my forecast of total-company NPC by $17,961,132, with $2,469,577 allocated to Wyoming. I also removed the restriction for Utah resources, but doing so produced no incremental impact on NPC based on the way it was modeled.

**F. <u>Non-Native Reserves</u>**

**Q. WHAT ARE NON-NATIVE LOADS AND RESOURCES?**

A. For purposes of this subsection of testimony, I refer to third-party generators and retail loads of other utilities located in the Company's Balancing Authority Areas ("BAA") as non-native loads and resources.[65] There is a material volume of generators including wind, solar, and thermal generators located in RMP's BAA that are not used by RMP to serve its retail customers. Similarly, there are several other load serving entities located in RMP's BAA, such as municipal and consumer owned utilities, that procure and deliver energy independent from the requirements of RMP's retail service customers. The non-native loads and resources forecast in RMP's BAAs for the test period are detailed in **Confidential Table BGM-2**, below.

[65] RMP retail customers in other jurisdictions are <u>not</u> non-native loads as I use that term in this testimony.

**Confidential Table BGM-2**

Non-Native Loads and Resources Included in RMP's BAAs[66]

Peak / Nameplate MW

[redacted]

**Q. HOW DO NON-NATIVE LOADS AND RESOURCES IMPACT NPC?**

A. As a Balancing Authority, the Company is required to balance all the loads and resources in its BAA, including non-native loads and resources. While non-native loads and resources separately track and account for the cost of their own energy requirements and production, RMP must still ensure that the entire BAA is in balance, including balancing for non-native loads and resources. As a result, the Company must provide load integration services to non-native loads and provide wind and solar integration services to non-owned wind and solar resources located in its BAA. These services require RMP to hold reserves for non-native load and generation customers, which impacts the cost of production from RMP-owned resources. Further, pursuant to BAL-002-WECC-3, the Company must also hold spinning and non-spinning contingency reserves services to these customers in order to satisfy the applicable NERC reliability standard.

[66] WIEC Exhibit No. 202.4 (RMP Response to WIEC DR 16.1, Confidential Attachment WIEC 16.1-2).

**Q. WHAT ARE RESERVES?**

A. Reserves are dispatchable generation capacity that RMP must withhold, or have available, to be capable to respond to uncertainty associated with loads, generation, and intermittent resources, including for non-native loads and resources. The classic example of reserves are contingency reserves, which RMP discussed in its July Update. For contingency reserves, a utility is required pursuant to NERC standards to have generation capacity available to respond within ten minutes in a contingency event, such as a forced outage. Thus, rather than selling the full output of a resource into the market, a resource that is holding reserves must be dispatched down to be capable of responding to such events, resulting in an opportunity cost to the utility. There are several different types of reserves, including both upward reserves and downward reserves. RMP generally categorizes these other reserves as regulating or flexibility reserves. Upward regulating reserves represent capacity that is available to be ramped up within a specified timeframe to accommodate things such as a generator tripping offline or an unexpected increase to load. Downward regulating reserves, on the other hand, represent capacity that is available to be ramped down within a specified timeframe to accommodate things such as an unexpected increase in variable generation or unexpected reduction to load. Since the reserved capacity cannot be used to serve native retail customers or sold into the market for the benefit of native retail customers, regulating reserves held for non-native customers result in material costs to RMP.

**Q. DO THE NON-NATIVE LOADS AND RESOURCES PAY RMP FOR PROVIDING THESE RESERVES ON THEIR BEHALF?**

A. Yes. The non-native loads and resources are FERC jurisdictional, Open Access Transmission Tariff ("OATT") customers. Under RMP's FERC approved OATT, non-native loads and resources are required to pay RMP for holding reserves on their behalf. Specifically, non-native loads and resources must pay RMP for providing regulation reserve services under OATT ancillary service Schedule 3[67] and Schedule 3A.[68] Non-native loads and resources must also pay RMP for providing contingency reserve services, including both spinning and non-spinning, under OATT ancillary service Schedule 5[69] and Schedule 6,[70] respectively.

**Q. ARE THE REVENUES FOR PROVIDING THESE SERVICES INCLUDED IN REVENUE REQUIREMENT?**

A. Yes. The revenue RMP receives for providing reserve services to non-native loads and resources are included in RMP's revenue requirement as wheeling revenues and can be found in RMP Witness Highsmith's workpaper titled "3.3 Wheeling Revenue."[71] The specific revenues assumed for each ancillary service schedule, including the schedules identified above, may be found in the workpaper version in Tab "3.3.1," by expanding the hidden cells underneath column "AL."

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[67] PacifiCorp Open Access Transmission Tariff, FERC Electric Tariff, Volume No. 11, Schedule 3 (effective Jan. 1, 2021).
[68] *Id.*
[69] *Id.* at Schedule 5 (effective Jan. 1, 2021).
[70] *Id.* at Schedule 6 (effective Jan. 1, 2021).
[71] *See* Direct Testimony of Nicholas Highsmith, RMP Exhibit 11.2, p. 56.

**Q. HOW DO THESE FERC APPROVED REVENUES COMPARE TO THE COSTS INCLUDED IN RMP'S NPC FORECAST?**

A. I prepared a modified NPC forecast that excluded the reserves associated with providing FERC jurisdictional contingency reserves services to non-native loads and resources under OATT ancillary service Schedules 5 and 6. I also prepared a modified NPC forecast that excluded the reserves associated with providing FERC jurisdictional regulation reserve services to non-native loads and resources under OATT ancillary service Schedules 3 and 3A. Based on those scenarios, I performed a comparison between costs RMP included in its NPC forecast for non-native loads and resources and associated ancillary service revenues included in revenue requirement. The results of that analysis may be found in **Table BGM-3**, below.

**Table BGM-3**
RMP OATT Revenues vs. Forecast NPC Cost from Non-Native Customers
Whole Dollars, Total-Company

| OATT Service Type | Forecast OATT Revenues | Forecast NPC Costs | Revenue Shortfall |
|---|---|---|---|
| Schedules 5 & 6 - Contingency Reserves | (5,761,461) | 141,893,045 | 136,131,584 |
| Schedules 3 & 3A - Regulation Reserves | (6,448,443) | 81,011,122 | 74,562,679 |
| Total | (12,209,904) | 222,904,167 | 210,694,263 |

As can be seen the revenues received from non-native OATT customers is only a small fraction of the cost RMP has forecast for serving those customers.

**Q. HOW DID YOU CALCULATE THE REGULATION RESERVES FOR NON-NATIVE LOADS AND RESOURCES?**

A. RMP includes an hourly time series in the AURORA model called "1_Regulating Margin." The workpapers supporting that time series contained only hardcoded values. Accordingly, in WIEC Data Request 16-1, RMP was requested to provide the workpapers supporting the regulation reserve values, along with an explanation for how they were calculated. In response RMP provided several spreadsheets which contain reserve calculations, although none of the values in any of the spreadsheets precisely matched the values RMP had included in the AURORA model. RMP was also requested to identify the reserves attributable to non-owned resources, to which RMP responded:

> PacifiCorp's regulation reserve requirements are calculated based on the aggregate nameplate capacity and capacity factor for all wind and solar in each balancing authority area (BAA). PacifiCorp has not separately identified regulation reserve volumes attributable to non-owned resources.[72]

As a result of these inadequacies in RMP's responses, I relied on the workpapers it provided which included regulation reserve values that were very close to, but did not precisely match, the values input into the AURORA model. Specifically, I relied on the workpapers titled. "NPC_Reg_Reserve_East_template CONF" and "NPC_Reg_Reserve_West_template CONF." Those files contained specific inputs for the regulation reserves attributable to non-native loads and resources. Using those files, I recalculated the reserve levels without the non-native loads and resources and, comparing back the original file, calculated the hourly

[72] WIEC Exhibit No. 202.4 (RMP's response to WIEC DR 16.1(c)).

level of reserves attributable to non-native loads and resources. This calculation yielded on average [redacted] MW of regulating reserves being for non-native loads and resources. Using the hourly values, I modified the hourly "1_Regulating Margin" timeseries in AURORA to exclude reserves I calculated associated for non-native loads and resources.

**Q. IS IT REASONABLE FOR WYOMING CUSTOMERS TO SUBSIDIZE NON-NATIVE LOADS AND RESOURCES?**

A. No. As a general principle, the costs of serving non-native loads and resources should be paid for by those loads and resources. Following that principle, including costs in NPC that exceed the level of revenues being collected from non-native loads and resources is not reasonable. It is unreasonable to require ratepayers in Wyoming to subsidize the cost of serving non-native loads and resources, and accordingly the revenue shortfalls detailed above are not reasonably considered in the NPC forecast. If RMP's FERC-approved OATT rates are inadequate to recover its cost of serving non-native customers, it would be most appropriate for RMP to seek to recover the funds through its FERC rates, not through an increase to Wyoming customers' rates.

**Q. WHY IS YOUR CALCULATION OF CONTINGENCY RESERVES FOR NON-OWNED LOADS DIFFERENT THAN THE CONTINGENCY RESERVE CHANGE RMP INCLUDED IN ITS JULY UPDATE?**

A. The $62,982,606 value RMP calculated in its July Update included only a portion of the modeled cost of contingency reserves for non-owned generation resources. My calculation removes the cost of contingency reserves for both non-native loads and non-native resources, leading to a value that is approximately double the cost RMP calculated for non-owned resources in its July Update.

**Q. WHY ARE THE IMPACTS SO LARGE?**

A. Part of the impact may be caused by an error in how RMP modeled contingency reserves in its July update generally. The AURORA model is not configured to evaluate reserves for non-native loads and resources. In its initial filing, RMP used a workaround where it added in the requirements of non-native load and generation, but correspondingly offset the modeled requirements with fictitious purchases and sales. While the precise cause is unknown, it may have impacted the zonal clearing prices for generation, causing uneconomic dispatch, and increasing the incremental cost of holding reserves for non-native services. There may be other errors with this modeling method, although it seems apparent that, in general, the AURORA model is not valuing contingency reserves consistent with the FERC approved costs.

**Q. HOW HAVE YOU ADDRESSED NON-NATIVE LOADS AND RESOURCES IN YOUR FORECAST?**

A. In my forecast, I have removed the reserves associated with non-native loads and resources from the AURORA model. In their place, I have modeled the FERC approved costs as an increase to NPC. By adding the "Non-Native Cont. Reserves" and "Non-Native Reg. Reserve" line items in **Table BGM-3,** above, the net effect of these changes in my NPC forecast was a reduction of $210,694,263 on a total-company basis, with approximately $28,969,536 allocated to Wyoming customers.

## V. NON-REVENUE REQUIREMENT ISSUES

**Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. In this section of testimony, I discuss non-revenue requirement issues, which are included in the revenue requirement recommendation of WIEC witness Higgins.

### A. State Income Tax Accounting

**Q. WHAT IS YOUR RECOMMENDATION FOR STATE INCOME TAX ACCOUNTING?**

A. In a revenue requirement calculation, two alternate tax accounting methods for state income taxes can be used: 1) a normalization method, as used by RMP; or 2) a flow-through method, as used by many other jurisdictions in the West. For state taxes, both methods are acceptable in a revenue requirement calculation. Unlike Federal income taxes, there are no requirements to use a normalization method of accounting for state income taxes. In this docket, I recommend RMP transition to a flow-through method of accounting for state income taxes. I propose this recommendation, in part, because RMP does not pay any material state taxes. The change will also mitigate the otherwise large rate increase that RMP has proposed in this proceeding and more closely captures the actual cashflow impacts of state income tax expenditures to RMP, better reflecting the cost of serving Wyoming customers.

**Q. WHAT IS NORMALIZATION ACCOUNTING?**

A. A normalization method of accounting is a statutory requirement for certain Federal income tax items, particularly accelerated depreciation and the investment tax credit. A normalization method spreads the impacts of income tax items, which are usually more favorable taxwise than book accounting, over the book life for the underlying tax item. Depreciation expense is accelerated for tax accounting purposes. The modified accelerated cost recovery provisions of Internal Revenue Code ("IRC") § 168, for example, might allow a depreciation deduction for utility plant over a 20-year period, whereas for book purposes, the same property might be depreciated over a 50-year period. While a utility gets a tax benefit from the shorter tax depreciable life, the normalization accounting requirements require the benefit of accelerated tax depreciation to be held in reserve and amortized over the longer 50-year period. In any given year, it is typical for the normalization method to result in ratepayers paying for more taxes in revenue requirement than the utility actually pays, with the excess applied as a reduction to rate base through accumulated deferred income taxes ("ADIT"). The excess taxes paid are called deferred taxes and often characterized as a source of zero cost financing, or an interest-free loan, and thus justified as a reduction to rate base.

**Q. HOW DOES FLOW-THROUGH ACCOUNTING DIFFER FROM NORMALIZATION ACCOUNTING?**

A. A flow-through method, however, is different, and in some ways simpler. Ratepayers pay only the amount of income taxes the utility pays. There are no deferred taxes. There are no interest-free loans. A flow-through method can be used for any income tax items that are not subject to normalization. Normalization is not required for state income taxes. Accordingly, in this docket, it is within the Commission's discretion to require RMP to transition to a flow-through method for state income taxes.

**Q. WHY ARE OTHER STATES' INCOME TAXES INCLUDED IN WYOMING REVENUE REQUIREMENT?**

A. Wyoming does not have a state income tax. Notwithstanding, the 2020 Protocol establishes how state tax expenses are allocated amongst the states, requiring the use of a blended state tax rate for all states. Section 3.1.7 of the 2020 Protocol, for example, states that tax expenses are allocated based on "the federal tax rate and PacifiCorp's combined State effective tax rate."

**Q. DOES THE 2020 PROTOCOL SPECIFY THE ACCOUNTING METHOD THAT MUST BE USED FOR STATE TAXES?**

A. No. The 2020 Protocol is an allocation framework, not an agreement on the accounting methods used to establish revenue requirement. Therefore, it is not controlling on whether the Commission may use a flow-through or normalization method of accounting for state income taxes. The 2020 Protocol explicitly states that "[n]othing in the 2020 Protocol is intended to abrogate any Commission's right or obligation to … determine fair, just, and reasonable rates based upon applicable laws and the record established in rate proceedings conducted by that Commission[.]"[73] Thus, the 2020 Protocol would not implicate a Commission decision to transition to flow-through accounting for state income taxes in this proceeding.

[73] 2020 Protocol, p. 3, lines 48-50.

**Q. DOES RMP PAY ANY MATERIAL STATE INCOME TAXES?**

A. No. While RMP's filing includes approximately $2,316,195 of state income taxes,[74] virtually none of those taxes are actually being paid. In all of RMP's major state tax jurisdictions, RMP has been generating significant net operating tax losses year-over-year, resulting in large net operating loss carryforward balances. RMP detailed the net operating loss carryforward balances in response to WIEC Data Request 1.19.[75] The individual state net operating losses from that response are detailed in **Confidential Table BGM-6**, below.

**Confidential Table BGM-6**
RMP State Net Operating Losses – Whole Dollars

[redacted]

**Q. HOW ARE THOSE STATE NET OPERATING LOSS CARRYFORWARD BALANCES CONSIDERED IN REVENUE REQUIREMENT.**

A. To account for these large net operating losses, RMP has included these net operating loss carryforwards as a $66,076,095 total-company, $8,369,000 Wyoming allocated, deferred tax asset included in rate base.[76] Inclusive of the

[74] Direct Testimony of Nicholas Highsmith, RMP Exhibit 11.2, p. 4, line 26.
[75] WIEC Exhibit No. 202.4 (RMP's Response to WIEC DR 1.19).
[76] Direct Testimony of Nicholas Highsmith, RMP Exhibit 11.2, p. 395.

Federal detriment, the balance included in rate base is $52,200,114 total-company or $6,607,000 Wyoming allocated. In other words, not only is RMP collecting in rates for tax expenses that it is not paying, RMP is proposing to earn a return on the balances it has not paid.

**Q. ARE THE NET OPERATING LOSSES A REAL COST TO RMP?**

A. No. The net operating losses are hypothetical, calculated on a stand-alone, proforma basis for RMP. In response to WIEC Data Request 1.20, RMP identified the states where it files a consolidated tax return with Berkshire Hathaway.[77] To the extent that in any given state RMP recognizes a taxable loss, Berkshire Hathaway is able to use that loss to offset its own state tax liability. Correspondingly, RMP has a intercompany tax agreement with Berkshire Hathaway that was provided in response to WIEC Data Request 1.21, where it is paid in connection with generating the state tax losses.[78] Section 2(b) of that agreement states that [redacted]" Accordingly, while RMP is including the state net operating loss carryforwards in rate base, those do not represent a real cash outflow to it because it is being reimbursed for the state losses from Berkshire Hathaway.

[77] WIEC Exhibit No. 202.4 (RMP's Response to WIEC DR 1.20).
[78] WIEC Exhibit No. 202.4 (RMP's Response to WIEC DR 1.21).

**Q. DOES TRANSITIONING TO A FLOW THROUGH METHOD ALLEVIATE THIS PROBLEM?**

A. Yes. When transitioning to a flow through method, only the actual amounts paid, or in RMP's case received, with respect to state taxes are included in rates, which eliminate issues associated with the tax benefit of net operating losses that are being reimbursed by Berkshire Hathaway.

**Q. HOW DOES TRANSITIONING TO A FLOW-THROUGH METHOD FOR STATE TAXES IMPACT REVENUE REQUIREMENT?**

A. There are two general impacts.

First, state tax expenses are restated based on current state taxes payable in the test period, excluding any provisions for deferred taxes. In response to discovery, RMP confirmed that $1,753,453 of deferred income tax expense was included in the test period.[79]

Second, previously accrued and ADSIT balances—*i.e.,* the interest free loans—are freed-up and available to be refunded to ratepayers. In discovery, RMP confirmed that $74,052,534 in ADSIT had been accrued as of the test period.[80] Thus, transitioning to a flow-through method for state income taxes will not only reduce tax expense, but will free up a material amount of ADSIT reserves from deferred taxes ratepayers formerly contributed to RMP, which can be refunded to offset the proposed rate increase. This refund is similar to the refund of Excess Deferred Federal Income Taxes that resulted with respect to tax reform.

[79] WIEC Exhibit No. 202.4 (RMP's Resp. to WIEC DR 4.11)
[80] WIEC Exhibit No. 202.4 (RMP's Resp. to WIEC DR 4.12)

**Q. IS IT PREFERABLE TO USE A FLOW-THROUGH METHOD OF ACCOUNTING FOR STATE TAXES?**

A. Yes. A flow-through method is more consistent with the actual cash-flow implications of state income taxes, and therefore, more accurately captures a utility's revenue requirement. Further, the flow-through method promotes generational equity because it offsets more revenue requirement of an investment in the early years of its life, which tend to be more expensive.

**Q. HOW IS FLOW-THROUGH ACCOUNTING MORE CONSISTENT WITH THE ACTUAL CASHFLOWS OF THE UTILITY?**

A. Flow-through accounting focuses principally on the cash-flows associated with tax expenses, not the timing of the underlying book-tax differences. One result of a normalization method, where tax benefits are spread out over the life of a resource, is that, in the long run, ratepayers consistently pay for more tax expense in rates than the utility pays. A utility, such as RMP, is consistently investing in new property and resource additions. As these new investments are made, deferred income taxes grow and accumulate. Under a normalization method of accounting, one would expect to pay more taxes than the utility pays in the early years of an asset's life and less taxes than the utility pays in the later years of an asset's life, as deferred taxes reverse. In practice, however, this reversal, and the benefit of paying less taxes than the utility in revenue requirement, never occurs. Because of ongoing property additions, any reversals are continually being offset by incremental deferred taxes, and as such, ratepayers can have little expectation of an eventual situation of paying income taxes less than what the utility pays due to reversal of formerly contributed deferred taxes. From this perspective the interest-free loan provided by ratepayers is never really repaid—it is continually and constantly being refinanced with higher and higher principal balances. Use of a flow-through method does away with this problem and the interest free loan altogether, and therefore, better reflects the long-term realities of how state income taxes impact utility cashflows.

**Q. DOES THE FLOW-THROUGH METHOD PROMOTE INTERGENERATIONAL EQUITY?**

A. Yes. The revenue requirement of a new utility plant addition is usually highest in the first years of service and declines over time. This presents generational inequity because the ratepayers who happen to be taking service from the utility plant when it is first placed into service will pay higher rates than ratepayers that take service later in the resource's life. By using the flow-through method, more tax benefits are recognized in the early years of a resource's life, offsetting some of the higher revenue requirement in those years. This results in a somewhat more level revenue requirement profile for the investment, promoting intergenerational equity. By spreading the tax benefits over the life of a resource under the normalization method, however, the effects of intergenerational inequity associated with a new utility plant addition are amplified.

**Q. DO OTHER UTILITIES USE A FLOW-THROUGH METHOD FOR STATE INCOME TAXES?**

A. Yes. Many jurisdictions with a state income tax, particularly those in the West, use a flow-through method for state income taxes in revenue requirement. Several states like Idaho[81] and California,[82] for example, have specific policies requiring the use of flow-through accounting for state income taxes that date back over 50 years. Thus, the flow-through method is an acceptable method for calculating revenue requirement. In **Table BGM-7**, below, I provide a list of regional utilities I am aware of that use flow-through accounting for state income taxes, though this is not a comprehensive list.

**Table BGM-7**
List of Utilities That Use Flow-Through Accounting for State Income Taxes[83]

| |
|---|
| Avista (Oregon & Idaho) |
| Intermountain Natural Gas (Idaho) |
| Idaho Power (Idaho) |
| Dominion Utah (Utah) |
| Northwestern (Montana) |
| Pacific Gas & Electric |
| San Deigo Gas And Electric |

[81] *See In the Matter of the Application of Idaho Power Company for Authority to Increase its Interim and Base Rates and Charges for Electric Service*, Case No. IPC-E-03-13, Direct Rebuttal Testimony of Bruce E. MacMahon, p. 8, lines 2-4.

[82] *See Interim order that conventional normalization methods shall be used for purposes of the Economic Recovery Tax Act of 1981*, Decision 93848, Order Instituting Investigation (OII) No. 24 (Dec. 15, 1981); *see also Application of San Diego Gas & Electric Company (U902E) for Approval of its Electric Vehicle-Grid Integration Pilot Program*, CPUC Docket A.14-04-014, Direct Testimony of Jonathan B. Atun, at JBA-7:10-11 (April 11, 2014).

[83] *See* Oregon Public Utilities Commission, Docket No. UG 153, Order No. 03-570, Attachment A, Appendix B, at 10 (Sep. 25, 2003); *See* Idaho Public Utilities Commission, Case Nos. AVU-E-10-01; AVU-G-10-01, Order No. 32070, at 8 (Sep. 21, 2010) (internal citations omitted); Idaho PUC Case No. INT-G-22-07, J. Darrington, Direct at 22:1-3 (Dec. 1, 2022); Public Service Commission State of Montana Docket 2022.01.001, Annual Report of NorthWestern Energy to the Montana Public Service Commission, at 50 (2021); Public Utilities Commission of the State of California, A.15-09-001, Petition for Modification of Decision 17-05-013 of Pacific Gas and Electric Company (U 39 M) to Reflect Tax Changes, Attachment B, Report of Pacific Gas and Electric Company on Revenue Requirement Revisions from the Tax Cut and Jobs Act of 2017 on the 2017 General Rate Case, at 6 (Sep. 1, 2015) (internal citations omitted); Public Utilities Commission of the State of California, A.14-04-014, Direct Testimony of Jonathan B. Atun, at JBA-7:10-11 (April 11, 2014) (internal citations omitted).

**Q. HOW DO YOU RECOMMEND TRANSITIONING TO THE FLOW-THROUGH METHOD IN THIS DOCKET?**

A. The method for transitioning was discussed in Idaho Case No. AVU-E-10-01, in which Avista transitioned from a normalization to a flow-through method accounting for state income taxes, as I am recommending for RMP.[84] As Avista discussed in that case, switching to the flow-through method "provided the opportunity to make the DSIT balance available to potentially offset the general rate case."[85] As noted previously, a principal beneficial aspect of the change in accounting method is that previously accrued ADSIT becomes available to be refunded to ratepayers. When transitioning to the flow-through method, the interest free loan made by ratepayers must be repaid. This is similar to the refund of excess deferred income taxes that occurs when tax rates are reduced through tax reform. These balances can be refunded over longer or shorter periods, depending on the Commission's preferences. For purposes of my analysis, I have assumed a 3-year amortization period, corresponding roughly to RMP's historical cycle of general rate case filings. Over the amortization period, the balance will be recorded to a rate base regulatory liability account and subject to a gross-up to be stated on a revenue requirement basis.

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[84] *See In the Matter of the Application of Avista Corporation dba Avista Utilities for Authority to Increase its Rated and Charges for Electric and Natural Gas Service in Idaho*, Case Nos. AVU-E-10-01, AVU-G-10-01, Order No. 32070, p. 9 (Sep. 21, 2010).
[85] *Id.* at 16.

**Q. WHAT IS THE IMPACT OF THE CHANGE ON REVENUE REQUIREMENT?**

A. Assuming a three-year amortization period, as I propose here, the impacts of the change in accounting on expense and rate base are detailed in **WIEC Exhibit No. 202.6**. WIEC witness Higgins calculates the revenue requirement impact of the full change in his revenue requirement model. As can be seen from my exhibit, when transitioning to flow-through accounting, accrued ADSIT balances are transitioned into a rate base regulatory liability account, dollar-for-dollar and subject to a gross-up to be stated on a revenue requirement basis. The regulatory liability is subsequently amortized over a three-year period as a reduction to pre-tax expense beginning with the rate effective date of the docket. Correspondingly, the rate base of the regulatory liability balance is reduced by one-half of the amortization amount, representing the average balance over the test period. Finally, deferred state income tax expense is removed from revenue requirement. Since the average test period deferred taxes are included in ADSIT, the regulatory liability balance is also reduced by one-half of the removed deferred state income tax expense. I have provided these values to WIEC witness Mr. Higgins for inclusion in his revenue requirement calculation.

**B. <u>Jim Bridger Units 1 and 2 Gas Conversion</u>**

**Q. WHAT IS THE STATUS OF THE GAS CONVERSION FOR JIM BRIDGER UNITS 1 & 2?**

A. At the end of 2023, Jim Bridger Units 1 and 2 will be taken out of service to undergo conversion into gas fired steam turbines. The units are not expected to return to service in their new capacity until March 1, 2024 for Jim Bridger Unit 1 and May 1, 2024 for Jim Bridger Unit 2.[86] During this time period, the two units will not be productive and will not be generating electricity for the benefit of ratepayers. In its initial filing, for example, RMP forecast that power costs are expected to increase by $22 million due to the lost generation associated with the conversion outage.[87] Notwithstanding this lost generation, RMP has proposed that ratepayers continue to pay for the operating expense associated with Jim Bridger Units 1 and 2 during the period when the units are taken out of service and prior to when the new generators come online.

**Q. HOW DO YOU PROPOSE TO HANDLE THE COST OF JIM BRIDGER DURING THIS PERIOD?**

A. RMP will not be incurring the costs of operating Jim Bridger Units 1 and 2 during the conversion process. Accordingly, my recommendation is to remove the operating expense of Jim Bridger Units 1 and 2 during the approximate three-month period when the units are out of service.

**Q. WHAT IS THE COST OF JIM BRIDGER UNITS 1 AND 2 DURING THE PERIOD IT IS OUT OF SERVICE?**

A. In **WIEC Exhibit 202.7**, I detail the operating expenses associated with Jim Bridger Units 1 and 2 during the period when it is out of service. I have provided the values in that exhibit to WIEC witness Mr. Higgins for inclusion in his revenue requirement calculations.

[86] WIEC Exhibit No. 202.4 (RMP's Response to WIEC DR 4.7).
[87] Direct Testimony of Ramon Mitchell, p. 19, lines 6-8.

### C. Production Tax Credit Rate

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE PRODUCTION TAX CREDIT RATE.**

A. In its initial filing in this proceeding, RMP forecast a PTC rate of [redacted] cents per kWh.[88] As I demonstrate in **WIEC Exhibit 202.8**, however, the PTC rate, which is set annually based on an index of inflation, will likely increase to 3.0 cents per kWh in 2024, and in no circumstance will the 2024 PTC rate be less than 2.9 cents per kWh. PTCs are included in the ECAM base and trued up with a 100% pass through in annual ECAM filings. Accordingly, for setting the ECAM base values provided to WIEC witness Mr. Higgins, I have used a 3.0 cents per kWh PTC rate, which results in a $970,450 Wyoming-allocated reduction to the ECAM base.

**Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?**

A. The PTC rate is established pursuant to IRC § 45.[89] The PTC rate was first authorized in 1993 and established at a baseline of 1.5¢/kWh. To account for inflation, the IRS adjusts the PTC rate each year by applying an "inflation adjustment factor." In IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is outlined as follows:

> The term "inflation adjustment factor" means, with respect to a calendar year, a fraction the numerator of which is the [Gross Domestic Product ("GDP")] implicit price deflator for the preceding calendar year and the denominator of which is the GDP implicit price deflator for the calendar year 1992. The term "GDP implicit price deflator" means the most recent revision of the implicit price deflator for the gross domestic

[88] WIEC Exhibit No. 202.4 (RMP's Response to WIEC DR 1.14).
[89] 26 U.S.C. § 45(b)(2) (2021).

> product as computed and published by the Department of Commerce before March 15 of the calendar year.[90]

In addition, when applying the inflation adjustment factor, the credit rate is rounded to the nearest multiple of 0.1 cents per kWh. Consequently, while the inflation adjustment factor changes every year, the PTC rate does not necessarily change each year. In 2024, for example, the unrounded PTC rate would need to exceed 2.95 cents per kWh to trigger an increase to 3.0 cents per kWh.

**Q. HOW DID YOU FORECAST THE PTC RATE FOR 2024?**

A. **WIEC Exhibit 202.8** contains an analysis showing how the GDP implicit price deflator is used to calculate the PTC inflation adjustment factor. As noted in IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is a simple fraction.

The numerator of the fraction is equal to the GDP implicit price deflator for the calendar year prior to the tax year. For tax year 2024, for example, the numerator will be based on the GDP implicit price deflator from calendar year 2023, which won't be published until the spring of 2024.

The denominator of the fraction is equal to the GDP implicit price deflator for 1992, the calendar year prior to the 1993 tax year when the PTC was first implemented.

The denominator of the inflation adjustment factor is a known value. The GDP implicit price deflator for calendar year 1992 was 67.325.[91] Thus, while the precise value for the inflation adjustment factor for calendar year 2024 is not yet

[90] *Id.* at § 45(e)(2)(B).
[91] This is based on the current index values. Note that the baseline year used to establish the GDP implicit price deflator index value has been updated, which can be seen in WIEC Exhibit 202.10.

known, the periodically published GDP price deflator values can be used to determine whether the ultimate inflation adjustment factor will trigger an increase to the PTC rate.

**Q. WHAT WAS THE INFLATION ADJUSTMENT FACTOR FOR 2023?**

A. The inflation adjustment factor for 2023 was 1.8909, resulting in an unrounded PTC rate of 2.83 cents per kWh.[92] Thus, while the PTC rate rounded down to 2.8¢/kWh in 2023, the unrounded PTC credit rate was within 0.02¢/kWh of 2.85¢/kWh and rounding up to 2.9¢/kWh in 2023.

**Q. WHAT INFLATION ADJUSTMENT FACTOR WILL RESULT IN AN INCREASE TO THE PTC RATE IN 2024?**

A. Based on the year end inflation adjustment factor, the PTC rate is guaranteed to increase to at least 2.9 cents per kWh in 2024, even if zero inflation were to occur in 2023. Further, given high inflation rates, it is more likely than not that the PTC rate will increase to 3.0 cents per kWh for calendar year 2024. The inflation adjustment factor must equal or exceed 1.9667 to trigger an increase in the PTC rate to 3.0 cents per kWh. Whether this level is achieved, however, depends on the 2023 GDP implicit price deflator, which, as noted above, is an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. Based on information that is known about the GDP implicit price deflator today, it can be determined that it is likely that the inflation adjustment factor will likely be sufficient to cause the PTC rate to round up to 3.0 cents per kWh in 2024.

[92] Credit for Renewable Electricity Production and Publication of Inflation Adjustment Factor and Reference Price for Calendar Year 2023, 88 Fed. Reg. 40400-40401 (Jun. 21, 2023).

**Q. WHAT LEVEL OF INFLATION THROUGH THE END OF 2023 IS REQUIRED FOR THE PTC TO INCREASE TO 3.0 CENTS PER KWH?**

A. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for the second quarter of 2023. Based on that publication, it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as inflation equals or exceeds 4.0% on an annualized basis for 2023, as measured by the GDP implicit price deflator. Given recent indications, it is likely that inflation will exceed this level for the year. For example, the annualized inflation rates, using the GDP implicit price deflator for calendar years 2021 and 2022 were 6.418% and 6.409% respectively. Recent federal reserve projections published on June 14, 2023, for example, forecast Core Personal Consumption Expenditures ("PCE") Inflation of 3.7% to 4.2% in calendar year 2023, and historically Core PCE Inflation has been approximately 1.6% less than the inflation rate measured using the GDP implicit price deflator.[93] Thus, these levels of Core PCI Inflation would imply inflation measured by the GDP implicit price deflator of 5.3% to 5.8%. Further information surrounding the actual inflation rates for 2023, however, will become available as this proceeding progresses.

**Q. WHAT IS THE IMPACT OF A 3.0 CENTS PER KWH PTC RATE?**

A. A 3.0 cents per kWh PTC rate will result in an approximate $7,122,224 increase to RMP's overall PTCs, which on a Wyoming basis represents an approximate $970,450 reduction to revenue requirement.

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[93] Federal Reserve Open Market Committee, June 14, 2023: FOMC Projections, Summary of Economic Projections at 2. See also https://www.federalreserve.gov/monetarypolicy/fomcprojtabl 20230614.htm (accessed Aug 8 2023)

## VI. CONCLUSION AND SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY?**

A. I believe that RMP's forecasted NPC for the Test Period is overstated, and in significant respects RMP has failed to support the NPC included in its July Update. The fact that RMP forecasts NPC for the calendar year ending 2024 to be 24.5% higher than *actual* NPC in calendar year 2022 should be seen as a red flag in this proceeding, particularly where market prices are coming down.

Based on the production cost modeling discussed above, I forecast NPC of $1,989,446,537 in 2024 with $282,053,049 allocated to Wyoming. My NPC forecast is comprised of the following recommendations:

- Removal of updated coal costs that RMP submitted in its July Update because RMP misrepresented the cost of the update and provided no basis to evaluate the reasonableness of the changes proposed.
- Adjustments to reflect refined modeling when AURORA is run on a more advanced computer architecture.
- Removal of the cost of purchasing carbon allowances for the Washington CCA because of the significant and discriminatory nature of such costs.
- Adjustments to more accurately forecast sales and purchases by simplifying the DA/RT adjustment to be consistent with historical impacts.
- Adjustments to market caps to be consistent with the way that the Commission considered market caps in past proceedings and to produce results that are more in line with historical actual sales levels.

- Removal of costs associated with the EPA Ozone Transport Rule because such costs are unlikely to occur in the test year.
- Adjustments to better reflect the costs associated with providing ancillary services to non-native loads and resources and to remove the associated subsidies embedded in RMP's forecast.

Further, with respect to the non-NPC issues, I recommend the Commission adopt flow-through accounting for state taxes because RMP is not paying state taxes, and using the flow-through method is more consistent with intergenerational equity concerns. I also recommend operating costs associated with Jim Briger Units 1 and 2 be removed from rates during the period that it is out of service. Finally, I recommend that the production tax credit rate be increased to $3.0/MWh considering inflation expected through the end of the calendar year.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

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**BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES BY APPROXIMATELY $140.2 MILLION PER YEAR OR 21.6 PERCENT AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM | DOCKET NO. 20000-633-ER-23<br>(Record No. 17252) |

**AFFIDAVIT, OATH AND VERIFICATION**

STATE OF NEVADA )
) SS:
COUNTY OF CLARK )

Bradley G. Mullins, being first duly sworn, on his oath states:

1. My name is Bradley G. Mullins. I am a Principal Consultant in the firm of MW Analytics. I have been retained by the Wyoming Industrial Energy Consumers to testify in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which has been prepared in written form for introduction into evidence in Docket No. 20000-633-ER-23.

3. I hereby swear and affirm that my answers contained in this testimony are true and correct.

Bradley G Mullins

Bradley G. Mullins
MW Analytics
Tietotie 2, Suite 208
Oulunsalo, Finland FI 90460

Subscribed and sworn to before me by Bradley G. Mullins this 10th day of August, 2023.

William E Bumphrey
NOTARY PUBLIC
STATE OF NEVADA
Appt. No. 18-2817-1
Expires July 10, 2026

Notary Public William E Bumphrey
Commission #: 18-2817-1

My Commission Expires: 07/10/2026
Notarial act performed by audio-video communication.