BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE 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 (RECORD NO. 17252) VOLUME V

TRANSCRIPT OF HEARING PROCEEDINGS

PURSUANT TO NOTICE duly given to all parties in interest, this matter came on for hearing on the 31st day of October, 2023, at the hour of 8:30 a.m., in the Commission Hearing Room, 2515 Warren Avenue, Suite 300, Cheyenne, Wyoming, before the Public Service Commission, Ivan H. Williams, Counsel, presiding, with Chairman Mary Throne, Deputy Chairman Chris Petrie and Commissioner Michael Robinson also in attendance. Also present Wesley Neuman, Counsel, Luy Luong, Michelle Bohanan, Nathan Brennan, Kelli Kolkman, Nathan Petrisin, Kelly Hunt, Melisa Mizel, Andrea Mitchell and Allyson Brackett, technical advisors to the Commission.

A P P E A R A N C E S

For Rocky Mountain Power:	MS. KATHERINE MCDOWELL MR. ADAM LOWNEY Attorneys at Law MCDOWELL RACKNER GIBSON PC 419 SW 11th Avenue, Suite 400 Portland, OR 97205
	MS. CARLA SCARSELLA MR. AJAY KUMAR Attorneys PACIFICORP 825 NE Multnomah Street, Suite 2000 Portland, OR 97232
For WIEC:	MR. THORVALD A. NELSON MS. ABIGAIL C. BRIGGERMAN MS. MICHELLE BRANDT KING MR. AUSTIN JENSEN Attorneys at Law HOLLAND & HART LLP 555 Seventeenth Street, Suite 3200 Denver, CO 80202
For the OCA:	MS. SHELBY M. HAMILTON Counsel WYOMING OFFICE OF CONSUMER ADVOCATE 2515 Warren Avenue, Suite 304 Cheyenne, WY 82002
For the Sierra Club:	MS. ROSE MONAHAN Attorney SIERRA CLUB 2101 Webster Street, Suite 1300 Oakland, CA 94612
For Senator Cale Case:	Pro se
For Walmart:	MR. JEFFREY S. FLEGE Attorney at Law CLARK FLEGE LLP 3440 Youngfield Street, Suite 276 Wheat Ridge, CO 80033

I N D E X

E X H I B I T S

	RECEIVED
WIEC Exhibit No. 212.3	909
WIEC Exhibit No. 212.4	910
WIEC Exhibit No. 241	917

MR. KUMAR: Yes.

MR. WILLIAMS: Okay. And so now we will hear from WIEC witnesses?

MR. NELSON: That's correct. WIEC would call as its first witness Mr. Brad Mullins.

MR. WILLIAMS: Good morning, Mr. Mullins.

THE WITNESS: Good morning.

MR. WILLIAMS: Will you please raise your right hand.

(Witness sworn.)

MR. WILLIAMS: Mr. Nelson, you may proceed.

MR. NELSON: Thank you. Sorry, I'm less prepared than Mr. Mullins.

BRADLEY G. MULLINS,

called for examination by Wyoming Industrial Energy Consumers, being first duly sworn, on his oath testified as follows:

DIRECT EXAMINATION

Q. (BY MR. NELSON) All right. Good morning, Mr. Mullins.

A. Good morning.

Q. First a logistical note. I don't think that you've been coached necessarily, but if during the course of your examination and cross-examination attorneys or the Commission ask you to refer to exhibits, you can pull them up on the computer screen there. Do you see that in front of you?

A. I do see that, and it looks fairly straightforward. So I should manage. Thank you.

Q. Would you please state and spell your name for the record.

A. My name is Brad Mullins, spelled B-r-a-d M-u-l-l-i-n-s.

Q. And, Mr. Mullins, by whom are you employed and in what capacity?

A. I'm employed by MW Analytics, a consulting firm that represents customers around the West, and I am the principal of that.

Q. And on whose behalf are you testifying today?

A. The Wyoming Industrial Energy Consumers.

Q. Have you caused to be prefiled in this case direct testimony and exhibits?

A. I have.

Q. And was that direct testimony and exhibits prepared under your direction and supervision?

A. It was.

Q. Okay. Starting with your -- the text of your direct testimony, do you have any corrections that you want to make to that testimony at this time?

A. I do have one typo to correct. On page 34 of that testimony, on lines 9 and 13, I refer to Account 447-Fuel, and that should have been FERC Account 547-Fuel.

Q. Thank you.

In that the course of reviewing the rebuttal testimony provided by PacifiCorp, is it true that you've also come to make some modifications to the recommendations that you are making to the Commission in this proceeding?

A. Correct.

Q. If I could ask you to please pull up Exhibit Number 212.3.

A. Okay. I have it.

Q. Okay. Can you please explain to the Commission what is being depicted in this exhibit.

A. All right. So this depicts the latest revenue requirement forecast that I prepared based on adjustments and changes presented in RMP's rebuttal testimony that I found to be reasonable.

MR. NELSON: Okay. Mr. Williams, I'd move for the admission of 212.3.

MR. WILLIAMS: Mr. Kumar, do you have an objection?

Mr. Lowney, I apologize.

MR. LOWNEY: No worries. The Company has no objection.

MR. WILLIAMS: Miss Monahan.

MS. MONAHAN: No objections.

MR. WILLIAMS: Miss Hamilton.

MS. HAMILTON: No objections.

MR. WILLIAMS: Mr. Phetteplace, do either Senator Case or Mr. Flege have a hand raised?

MR. PHETTEPLACE: No hands raised.

MR. WILLIAMS: That exhibit is received into the record, thank you.

(WIEC Exhibit No. 212.3
received into evidence.)

Q. (BY MR. NELSON) Okay. Can you please now take a look at Exhibit 212.4.

A. Okay. I have that.

Q. And can you describe what that exhibit is, please.

A. That is the net power cost study supporting my recommended level of net power costs.

MR. NELSON: Okay. I would move for the admission of Exhibit 212.4.

MR. WILLIAMS: Mr. Lowney, any objection?

MR. LOWNEY: No objection.

MR. WILLIAMS: Miss Monahan.

MS. MONAHAN: No objection.

MR. WILLIAMS: Miss Hamilton.

MS. HAMILTON: No objections.

MR. WILLIAMS: Mr. Phetteplace, may I just impose upon you to tell me as we proceed if either Senator Case or Mr. Flege raise their hand.

MR. PHETTEPLACE: I will do that.

MR. WILLIAMS: Thank you. That exhibit is received into the record as well.

(WIEC Exhibit No. 212.4 received into evidence.)

MR. NELSON: Great.

Q. (BY MR. NELSON) Mr. Mullins, have you prepared a summary of your testimony for the Commission?

A. I have.

Q. Given the fact that you cover a wide variety of different topics, I'm going to sort of talk to you through your summary in different piece parts.

So to start us with, if you could please just describe generally the examination that you did in this case regarding net power costs and the Aurora model.

A. Great. Good morning, Commissioner Robinson, Deputy Chair Petrie and Chairman Throne. I appreciate the opportunity to be here today to testify on behalf of the Wyoming Industrial Energy Consumers. I sponsored testimony in this proceeding on issues surrounding the 2024 forecast of net power costs, or NPC, as well as a few discrete revenue requirement issues. I'll briefly walk through these issues discussing NPC first.

So in this case Rocky Mountain Power, or RMP, is requesting a 24.34 percent rate increase. An increase of this magnitude is going to have major implications for both businesses, individuals and families in the state. This is an important case, and as we have seen, most of the requested increase is being driven by NPC.

The current level of base NPC included in rates today from the 2020 GRC is $1.431 billion on a total-Company basis. At that time we were told that the $3.2 billion investment in EnergyVision 2020, which included over 1,000 megawatts of new Wyoming wind resources, repowering of the existing wind fleet and the associated Gateway transmission investment, was going to materially reduce NPC. For one reason or another, however, that reduction never occurred.

Since then, actual NPC has increased to approximately $2.040 billion in 2022. In its rebuttal, RMP is requesting that the Commission approve an even higher NPC baseline of 2.518 billion -- sorry, excuse me, $2.518 billion, which equates to a Wyoming-allocated NPC of $354.8 million.

I have reviewed RMP's forecast, and based on my analysis, I am forecasting a major increase to NPC relative to both the 2020 GRC and 2022 actuals. As detailed in

Exhibits 2. -- 212.3 and 212.4, my forecast supports an NPC of 2.166 billion or $307.1 million Wyoming allocated.

So notable in this case is the use of a new model called Aurora. And that compares to the former model that was used called GRID. Given the use of a new model, it is expected that there will be challenges and issues to work through.

I have been using the Aurora model since 2014 for other utilities, and to be clear, Aurora is a great model. It is important to note, however, that Aurora is different than GRID. It is primarily a power market model, and it was not designed specifically to simulate single-issue or single-utility closed system dispatch in the same way as the GRID model was. To its credit, however, RMP has developed several modeling techniques and work grounds to get the Aurora model to behave similar to the GRID model.

I'm not aware of any other utility in the West that uses Aurora with these same techniques. And while I think RMP has generally done a good job developing this model, there remain issues with some of these techniques.

Q. Can you please take a moment and describe for the Commission the specific issues that you continue to see going forward with how the Aurora model is implemented in this case.

A. Certainly. So before discussing items of disagreement, I will touch on the items that are not at issue. In rebuttal, RMP acknowledged WIEC's testimony that the Ozone Transport Rules will not apply to Utah or Wyoming in the test period. Relative to the July Update, this reduced NPC by 22 million total-Company or 3.2 million Wyoming-allocated.

Following my direct testimony, I contacted Energy Exemplar, the maker of the Aurora model, to obtain a backdated version of the Aurora model and confirmed that the minor differences between the NPC run on my computer and the NPC calculated in the July Update were attributable to the model update version, not differences in computer architecture.

After reviewing RMP's rebuttal testimony, I also found it reasonable to accept the use of the Commission-approved market cap method for nonliquid markets rather than the 95th percentile approach that I had recommended.

And finally, following my direct testimony, I was able to review RMP's July Update coal supply work papers which were provided in mid-September and the rebuttal testimony, and based on that information, I have gained more comfort around those costs, though I continue to disagree with the way that update was presented in the July Update, as well as the lack of testimony and supporting work papers supporting the changes that were made and the

Company's very limited responses to discovery on this issue.

Now, in terms of the July Update, it's also necessary to point out there was only a very short time to review the update, and the information RMP provided in the update was scant to say the least. There were significant new modeling changes introduced, such as wholesale revisions to the DA/RT adjustment, which were supported with one or two vague sentences of testimony.

Also complicating the update was the fact that RMP did not use its initial filing as the starting point for documenting the changes that it was proposing. Rather, it used a completely different Aurora model run as its starting point and then worked backwards to document the impact of some but not all of the changes that were made. This led to an excessive $164.2 million system balancing adjustment, which was an unexplained and undocumented increase to NPC relative to the initial filing.

In order to avoid unnecessary complication, WIEC recommends that the Commission should consider requiring RMP in future cases to present an update of its NPC forecast with sufficient supporting testimony for each material change with RMP's direct testimony NPC forecast as a starting point and with the Aurora model version and any other modeling changes not native to Aurora clearly detailed in supporting testimony. This will help all parties and the Commission better understand the inputs to and the modeling assumptions around RMP's NPC.

Now turning to the matters in dispute. There are four NPC items that are -- that remain at issue. First, the Washington Climate Commitment Act, or CCA; second, the day-ahead, dash, real-time or DA/RT adjustment; third, market capacity limits or market caps for liquid markets; and finally, third-party or non-native reserves.

Q. Let's take each of these in pieces. If you could please explain to the Commission the adjustment that you're proposing relative to the Washington CCA and the impacts that that adjustment has on net power costs.

A. Certainly. The CCA is a Washington state policy that, among other things, establishes a Cap and Invest Program for greenhouse gas emissions. The policy went into effect on January 1, 2023. In this case RMP has requested including the costs of Washington state's greenhouse gas policy in Wyoming customer rates. The impact of this treatment is significant, representing an approximate $63.4 million total-Company cost or $9.1 million on a Wyoming-allocated basis.

In my forecast, I have removed these costs. There are several reasons why it is not reasonable to include costs of Washington state's greenhouse gas policy in Wyoming customer rates. Foremost, Washington has effectively exempted its own state electric consumers from the application of the CCA by providing no-cost CCA allowances to cover the compliance obligations of in-state loads. In PacifiCorp's ongoing rate case in Washington, for example, there are no CCA allowance costs nor the associated impacts on dispatch included in revenue requirement.

Exempting in-state loads while requiring Wyoming customers to pick up the tab not only undermines the credibility of the program, but is unfair and unreasonable to Wyoming customers.

Importantly, the CCA is a new policy that was not considered at the time the Commission approved the 2020 protocol, and suggestions that the Commission is bound by the terms of the 2020 protocol to include the unfair and unreasonable costs of Washington state's greenhouse gas policy in Wyoming customer rates is not consistent with my reading of that document.

Despite the Company's stated position on this, the CCA is not a tax. It's a policy. And the longstanding principle of cost allocation in a multistate process is that states are responsible for the policy costs that they impose on the system.

Finally, as of Friday of last week, the Oregon

Commission agreed with this and disallowed recovery of Washington's CCA costs in Oregon customer rates.

Q. On that point, Mr. Mullins, can I please ask you to take a look at what's been marked for identification as WIEC Exhibit Number 241.

A. Okay.

Q. And do you recognize this as the Oregon decision that you just mentioned in your summary a moment ago?

A. I do.

MR. NELSON: Mr. Williams, I'd move for the admission of Exhibit Number 241.

MR. WILLIAMS: Mr. Lowney, does the Company object?

MR. LOWNEY: No objection.

MR. WILLIAMS: Miss Monahan.

MS. MONAHAN: No objection.

MR. WILLIAMS: Miss Hamilton.

MS. HAMILTON: No objection.

MR. WILLIAMS: It's received into the record.

(WIEC Exhibit No. 241
Received into evidence.)

MR. NELSON: Thank you.

MR. KUMAR: I would just like to clarify this is the redacted version of the order, correct, the public version?

MR. NELSON: So I believe the answer to that is yes, but can I confirm with Mr. Mullins. Mr. Mullins, is it your understanding this is -- yes, I'm sitting here staring at this. Yes, this is the redacted version of the order. It's like I'm pretty sure. Yes, sir.

MR. WILLIAMS: Thank you. Please proceed.

MR. NELSON: Which I think is good because I don't think I have the nonredacted version. At least I hope I don't.

Q. (BY MR. NELSON) Okay. Mr. Mullins, can you please address now the second of the open NPC issues that you mentioned earlier, and that is the adjustments or the changes to the adjustment that you recommend to the day-ahead/real-time issue.

A. Certainly. The issues surrounding the DA/RT adjustment are probably the most complicated of this case, although most of that complication is being driven by the fact that RMP made wholesale changes to the Commission-approved DA/RT adjustment method in its July Update, which increased NPC by $65.8 million on a total-Company basis.

Making things even more complicated is the fact that there was no explanation for the change, which RMP said was a mere correction. RMP did not exchange its justification for making this change until its rebuttal testimony.

The DA/RT adjustment itself recognizes that RMP intends to purchase more in high-priced hours and correspondingly sell more in low-priced hours. Monthly market prices, however, are calculated as an arithmetic average over all hours in a month. Accordingly, for any given market, the weighted average cost of purchases for RMP is generally going to be higher than the average monthly market price. Similarly, the cost of sales is going to be lower than the average. These differences multiplied by the volume of purchases and sales is the DA/RT adjustment.

In the four years ending in 2022, this difference resulted in an average of $61.5 million in costs relative to average monthly market prices.

Now, in a properly configured model, there is no need for a DA/RT adjustment. Based on the hourly load and hourly price inputs into the model, it will automatically purchase more in high-priced hours and sell more in low-priced hours resulting in a model DA/RT adjustment that is consistent with the historical pattern.

That is the reason why we have these hourly models to begin with. In the GRID model, however, the opposite was occurring. There were more sales in high-priced hours and more purchases in low-priced hours resulting in a DA/RT -- a modeled DA/RT adjustment that was negative.

By RMP's account, this was due to the fact that the GRID model was overoptimized. In the 2015 GRC, RMP developed a modeling method to address this issue. It involved two steps: First, there was an adjustment to market prices for sales and purchases made inside the model.

Second, because this modeling approach still produced different results than the historical impacts, there was a second spreadsheet adjustment made outside of the model that tied the modeled impacts back to the historical average results.

I call this first step the price adjustment and the second step the historical adjustment, although the second step is sometimes referred to as the volume component by the Company.

In its July Update, however, RMP changed this. It introduced a newly coined term, "artificial arbitrage revenues." The DA/RT adjustment, however, has never had anything to do with arbitrage revenues. What actually happened was that the first step, the price adjustment in Aurora, was producing a model DA/RT adjustment of approximately $128.1 million. Subsequently, the historical adjustment or volume component was reducing that impact by $66.6 million down to the historical average of $61.5 million. From this we can see that, unlike the GRID model, the price adjustment in Aurora was dramatically overstating the DA/RT impacts relative to the historical average.

RMP apparently did not like this result, in its rebuttal came up with a new theory that instead of being an adjustment that ties the model DA/RT price adjustment back to the historical average, the 66 point million dollar (sic) historical adjustment was now arbitrage revenues, which witness Mitchell points out that RMP has only recognized approximately $800,000 of arbitrage revenues historically.

By conflating these two completely different concepts, witness Mitchell attempts to justify essentially eliminating the historical adjustment step reducing the impact of that step from a $66 million benefit down to less than $1 million.

This unsupported DA/RT method change should be rejected. Apart from the procedural issues of introducing this change in the update and explaining it in rebuttal, the introduction of arbitrage revenues into the DA/RT modeling method does not obviate the need for an adjustment which reduces the model to DA/RT impacts back to the historical average.

Those are separate and distinct adjustments. In fact, considering arbitrage revenues would reduce the impact of the DA/RT adjustment even further. Eliminating this method change results in a $61.9 million total-Company or $8.9 million Wyoming-allocated reduction in my forecast.

Now turning to the second part of my recommendation on the DA/RT adjustment. Because the price adjustment in Aurora was producing modeled impacts that are so much greater than the historical average, it was apparent that Aurora is not overoptimizing transactions in the same way as the GRID model was.

When I removed the price adjustment completely from the July Update, it resulted in a modeled price adjustment of $32.2 million. While these impacts are still less than the historical average DA/RT impacts, they produce a result that is closer to the historical results than the use of the price adjustment in Aurora. Getting these values is close because, in addition to the effects on purchases and sales, the price adjustment also has ancillary impacts on system dispatch that are not captured in the DA/RT adjustment.

With the transition to Aurora, my recommendation, therefore, is to remove the modeled price adjustment but continue to make an adjustment outside of model to tie the historical -- to tie to the historical DA/RT impacts consistent with the Commission-approved method. This change resulted in a further $12.3 million total-Company or $1.8 million Wyoming-allocated reduction in my forecast.

Q. Mr. Mullins, turning to the next issue that remains in dispute, can you please talk about the adjustment to the market caps that you continue to recommend going forward.

A. Certainly. Market caps are an issue that have been around for a long time and subject to a great deal of controversy and Commission scrutiny. Market caps are limits on the amount of sales that can be made at any particular market hub in the model.

Importantly, in the absence of market caps, the ability for Aurora to model sales transactions is not unlimited. This is a common misconception. Absent market caps, the ability for Aurora to model transactions is limited by transmission capability to the individual market hubs, which represent the real-world constraint that RMP faces for transacting at these locations.

Market caps, on the other hand, place a further restriction on the ability of the model to make sales transactions justified largely based on market liquidity concerns.

In my testimony, I have recommended adhering to the Commission's currently approved method for market caps, which applies to illiquid markets but not to liquid markets. Liquid hubs such as Mid-Columbia and Palo Verde have not had market caps applied in past proceedings.

Note that RMP changed this assumption in its direct testimony applying market caps to all market hubs and offered no explanation for the change. Contrary to RMP's assertion, the major power market hubs in the West continue to be liquid.

Accordingly, I recommend that the established Commission-approved method, which excludes market caps from liquid market hubs, be applied in this docket. This reduces NPC by 51.4 million total-Company or 7.4 million Wyoming-allocated.

It is also necessary to point out that in this adjustment I have considered the Four Corners market to be a liquid market given the trading activity in relationship with the Palo Verde market.

Most of the impact of my adjustment is being driven by the Four Corners market. Approximately $41.2 million total-Company or 5.8 million Wyoming-allocated of my adjustment was attributable to Four Corners, whereas 10.2 million total-Company or 1.6 million Wyoming-allocated was attributable to Mid-Columbia and Palo Verde.

Q. Mr. Mullins, can you now please turn to the last of the adjustments that you are recommending with regards to net power costs and talk about the adjustment to the third-party reserves and the impact that has on your recommended net power cost.

A. Certainly. So turning to third-party or also referred to in my testimony as non-native reserves, these are reserves that RMP must hold for third parties, such as wind integration for non-owned wind resources and balancing services for third-party non-native loads.

As a general principle, Wyoming customers should not have to pay any more or less in rates as a result of services being provided to third-party customers.

As we see, however, Wyoming customers are being rates -- sorry.

As we see, however, Wyoming customer rates are being increased as a result of these services, which means that we are subsidizing those third-party customers, and the impacts relative to the open access transmission tariff, or OATT, revenues is staggering.

My recommendation in this case is simple. Limit the modeled cost of third-party reserves included in NPC to the FERC-approved costs that RMP recovers from those customers. This is not a disallowance. It is merely revaluing the third-party reserves in NPC in the same way that FERC values them. This adjustment has impacts on both regulation reserves, which is things like wind integration as well as contingency reserves, which are the reserves held primarily for forced outages.

In discovery we asked RMP to provide the amount of regulation reserves attributable to third-party resources in Aurora. RMP did not provide this calculation, though it did ultimately provide that information in its rebuttal testimony.

Compared to the values RMP presented, my estimate in my direct testimony produced a level of third-party regulation reserves that was only about 10 megawatts different than RMP's calculation.

Accordingly, in Exhibit 212.3, I have updated my calculations using RMP's calculated third-party regulation reserves.

I have also detailed the rate recommendation separately for contingency reserve services and regulation reserve services. As can be seen, using the FERC-approved costs for contingency services results in a $116.3 million total-Company and $16.7 million Wyoming-allocated reduction to my NPC forecast. For regulation reserves, it results in a $47.0 million or $6.8 million Wyoming-allocated reduction to my NPC forecast.

Collectively, these adjustments result in a $163 million total-Company reduction, and this compares to the approximate $125 million value that RMP calculated for these same items in rebuttal testimony.

Notably, with respect to contingency reserves, RMP did not identify any errors or corrections to my modeling. But there is a big difference with respect to how I modeled the removal of third-party contingency reserves and the way that RMP did.

As I discussed in direct testimony, RMP uses a modeling technique which includes third-party loads and resources in Aurora as purchases or sales, but then applies an offset through a corresponding purchase and sale.

When I calculated my adjustment for contingency reserves, I removed the third-party loads and resources completely from the model, including the offsets. RMP, on the other hand, simply toggled off the reserve requirement for the third-party loads and resources but left the offsetting purchases and sales in the model.

It turns out that the difference between these two approaches had a major impact on NPC. In my study, toggling off the third-party contingency reserves reduces NPC by only $42.1 million, whereas eliminating the third-party loads and resources altogether reduced NPC by $116.3 million. This means that the reason that the cost of contingency reserves is so high is due to the fact that there is a $74.1 million modeling error associated with the workaround of using offsetting purchases and sales to model contingency reserves, which is unrelated to the actual reserves themselves.

When asked about this in discovery in WIEC's set 25, RMP could offer no explanation for this difference. Accordingly, this modeling error is all the more reason to simply use the FERC-approved cost for third-party reserves in NPC as I have recommended.

Q. Finally, Mr. Mullins, in your testimony, you identify several recommendations to the Commission that impact the overall revenue requirement but are not specifically tied to net power costs. Can you please summarize your non-net power cost recommendations at this time.

A. Certainly. So there are three additional issues that I had raised. First is state tax flow-through. And RMP has accrued net operating losses in all of its state taxing jurisdictions and regularly does not pay any material state income taxes. This is particularly true given that it files consolidated returns with Berkshire Hathaway and is reimbursed for tax losses that it generates for the consolidated group.

Considering this, I recommend transitioning to a flow-through method for state taxes, which will establish rates only based on taxes RMP pays.

This approach is consistent with the way that state taxes are included in rates in many states in the West, including states such as California, Idaho and Montana. Additionally, making such a change also frees up taxes that had been formerly overpaid, which I recommended be refunded to ratepayers over a three-year period. This change will not just benefit customers today, but will also benefit future ratepayers through reduced state income taxes included in rates.

Second, I also recommended that the operating expenses associated with Jim Bridger Units 1 and 2 be removed from revenue requirement during the approximate three-month period when those plants are out of service to be converted to gas-fired operations.

Finally, in direct testimony, I presented a forecast of the production tax credit rate, or PTC rate, for 2024 and recommended increasing it to 3.0 cents per kilowatt-hour compared to the 2.9-cents-per-kilowatt-hour rate assumed in RMP's filing.

Since filing my testimony, the Department of Commerce Bureau of Economic Analysis has issued two updates to the 2023 second-quarter gross domestic product implicit price deflator calculation that I used in my forecast. In the September 29th update the Department of Commerce changed the baseline used to calculate this index value.

This change makes it less likely that the PTC rate will increase to 3 cents in 2024. Accordingly, while it is still possible that it will increase in 2024, I am withdrawing my recommendation on the PTC rate.

So this concludes my summary of issues included in my testimony. Once again, I do appreciate the opportunity to be here today and to testify before the Commission, and I look forward to questions.

MR. NELSON: Thank you, Mr. Mullins.

Mr. Williams, the witness is available for cross-examination questions from the Commission staff and the commissioners.

MR. WILLIAMS: Thank you. Let's take a break, and we'll reconvene at 10:25.

(Hearing proceedings recessed 10:09 a.m. to 10:25 a.m.)

MR. WILLIAMS: We are back on the record.

Mr. Lowney, do you have questions for Mr. Mullins?

MR. LOWNEY: I do. Thank you.

MR. WILLIAMS: Please proceed. I would note that we will take a break from Mr. Mullins' cross at eleven o'clock to see if there are public comments and then resume.

CROSS-EXAMINATION

Q. (BY MR. LOWNEY) All right. Good morning, Mr. Mullins.

A. Good morning.

Q. Let's start with your tax adjustment. If you could turn to Exhibit 202, which is your testimony.

A. Okay.

Q. At page 67.

A. Okay.

Q. And if you begin on line 8, you testified that "In a revenue requirement calculation, two alternative 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 that the West." Do you see that?

A. I do.

Q. And then a little further down you recommend in this case that "RMP transition to a flow-through method for accounting for state income taxes," correct?

A. Correct.

Q. Now, if you could please flip over to page 74 of your testimony. And beginning on line 22 at the bottom of that page, you again testify that "Many jurisdictions with a state income tax, particularly those in the West, use a flow-through method for state income taxes in revenue requirement." And you continue that "Several states like Idaho and California, for example, have specific policies requiring the use of flow-through accounting for state income taxes that date back over 50 years." Do you see that?

A. I do.

Q. Okay. Let's start with the state of Idaho. If you could please turn to Exhibit 74 -- or excuse me, Exhibit 52, my mistake.

A. And I apologize. It was asking me for a password.

Q. I cannot help you with that.

MR. WILLIAMS: I believe it is on the screen.

THE WITNESS: Okay.

MR. WILLIAMS: Were you able to get in, Mr. Mullins?

THE WITNESS: I was, I was. Can you please repeat the exhibit number.

Q. (BY MR. LOWNEY) Exhibit 52, it's one of Rocky Mountain Power's cross-examination exhibits. It's an order from the Idaho Public Utilities Commission.

A. Okay.

Q. All right. And just for context, this is an order that's dated February 28, 2011. Do you see that?

A. I do.

Q. And it was in an application of Rocky Mountain Power for approval of changes to its electric service schedules. Do you see that?

A. I do.

Q. Now, if you could turn please to page 62 of the exhibit. And at the very bottom of that page there's a heading C that says, "Tax Issues."

A. Okay.

Q. And if you continue over to the next page, page 63 of the exhibit, the very first sentence in the first full paragraph states, "The Company also requests approval to move to full normalization treatment of income taxes for purposes of setting rates."

And the next sentence says, "Staff supports this recommendation." And then it says, "We accept the Company's recommendation to fully normalize the repairs deduction and all other temporary book-tax differences." Do you see that?

A. I do.

Q. Now, your testimony, then, that says Idaho requires flow-through accounting is not correct, is it?

A. Well, of course, PacifiCorp has sort of different treatment, but for the other electric utilities, including Idaho Power and Avista, those both use the flow-through method for state income taxes.

Q. But it's not a universally applicable policy in the state, is it?

A. Yeah, I guess not. But it is -- they do explicitly use it for Avista and Idaho Power, and that was based on the policy that they set, you know, many years prior, and I do realize that PacifiCorp does have a different treatment there.

Q. All right. Well, let's look at that time frame. You said "many years earlier," and I believe in your testimony you said these states have had these policies dating back over 50 years. If you could flip back to Exhibit 202. And this time to page 76.

A. Okay.

Q. And beginning on line 3, you make reference to an Idaho case in which "Avista transitioned from normalization to flow-through method accounting for state income taxes"?

A. Yep.

Q. Do you see that?

And just looking at the date of that case, that was a 2010 case; is that right?

A. Right.

Q. So clearly that policy has not gone back 50 years, has it?

A. So in this particular case, it was, I guess, discovered that Avista was not using the flow-through method for state taxes, and that was inconsistent with the state policy and inconsistent with the way it was being done for at the time all the other utilities. And so they required them to make a change, and that change is actually quite similar to what we're recommending in this case. It involved removing the deferred portion of state income taxes as well as refunding the accumulated deferred portion as well.

Q. And if you could just flip one page earlier to page 75 of your testimony. You have a Table BGM-7 that includes utilities that you testify use flow-through accounting for state income taxes. Do you see that?

A. Yep.

Q. And you cite again Avista and you include Oregon as well as Idaho, correct?

A. Correct.

Q. Now, just to be clear, Oregon has no state policy requiring flow-through. Is that true?

A. That is true. So Avista is the only -- it's the only utility in the state of Oregon that uses a state flow-through method, and the distinction for Avista is that they have approved state net operating loss carryforwards, and because of that, you know, they weren't paying any taxes. And so it was determined that they should use a flow-through method rather than the normalization method because that more fairly captures the actual taxes they are paying.

Q. And thinking about other electric utilities in Oregon, isn't it true that you recommended that Portland General Electric Company also transition to the flow-through method?

A. I did.

Q. And in response to that, Oregon Commission staff opposed your recommendation because, according to them, it was unfair to customers across time. Is that true?

A. So the Oregon litigation staff did file surrebuttal testimony in Portland General Electric's recent rate case where they didn't outright reject or disagree with what we had proposed. They didn't necessarily agree with it either. They said that they might be open to it if the amortization period was longer. And since that was rebuttal testimony and the case was ultimately settled, we never responded or dealt with that, that issue.

Q. And that settlement, just to be clear, did not require Portland General Electric to transition to flow-through, correct?

A. Right. So the settlement covered a large number of issues. So with Portland General Electric, we have a pretty good track record and relationship with them where we very frequently settle cases. And I wasn't involved in this particular settlement, but I do know there were a lot of sort of give-and-take items in the settlement, and I do know that my, you know, particular customers were comfortable with the end result of that settlement.

Q. Okay. If you could turn to page 67 of Exhibit 202.

A. Okay.

Q. And I'm going to direct your attention to the very last line, line 23.

A. Okay.

Q. Where the sentence begins, "A normalization method spreads the impact of income taxes, which are usually more favorable taxwise than book accounting over the book life for the underlying tax item." Do you see that?

A. I do.

Q. And then a little further down in that same paragraph beginning on line 9, you testify that "In any given year, it is typical for the normalization method to result in ratepayers paying 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, or ADIT" -- that's A-D-I-T.

And you continue on, "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." Do you see that testimony?

A. I do.

Q. Now, while you call it an interest-free loan, in fact, customers do earn interest equal to the Company's weighted average cost of capital for those deferred tax balances; isn't that true?

A. Yeah, I think that's a fair characterization. So it's -- you know, it's an interest-free loan to the utility, and they include that in rate base as a reduction to rate base, and ratepayers get the benefit of that. So from some perspective, it's kind of like the ratepayers giving PacifiCorp a loan and earning interest on that loan. And I guess kind of the question is whether, you know, ratepayers really should be giving loans to the utility or not, you know, particularly in light of some of the unique circumstances for PacifiCorp.

Q. Now, if you could flip forward, please, to page 73 of that same exhibit.

A. Okay.

Q. Beginning on line 16 you testified that, "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." Do you see that?

A. I do.

Q. And in the next sentence you attribute that to ongoing property additions, which means that "...any reversals are continually being offset by incremental deferred taxes," and so "ratepayers can have little expectation of an eventual situation of paying income taxes less than what the utility pays to the reversal of formerly contributed deferred taxes."

Now, if I could refer your attention to Exhibit 37, please. And I'm going to direct your attention to page 6 of the exhibit, which is sort of hard to see unfortunately, but it's easier if you track it, it's page 17-11 of the original document.

A. Okay.

Q. And under the heading sub (a), it says, "The Attack on Normalization--The Phantom Tax Argument." Do you see that?

A. I do.

Q. And the first sentence says, "In regulatory proceedings, opponents of normalization often resort to the 'phantom tax' argument." And it continues, "The argument relies on the assumption that, because a utility's business would probably continue to grow, the deferred tax account will also continue to grow indefinitely. The phantom tax advocates contend that, as the deferred taxes grow at a rapid pace, there will always be more revenues collected to cover the deferred tax expense than the deferred taxes paid out. They further allege that this gives rise to a permanent tax savings rather than a tax deferral that would eventually be paid out when temporary differences reach a reversal." Do you see that?

A. I do.

Q. And you would agree that's essentially describing what you just walked through in your testimony, correct?

A. I think generally, but, you know, I probably wouldn't call it the phantom tax argument, per se. I mean, it's -- you know, I don't think I would disagree with anything that is said in this section. So I think it is similar to long-term debt where the debt is continually being refinanced at higher and higher levels, but I think the point that I am making here is that really the taxes that are paid are always going to be less than the total tax expense because of this situation. And recognizing that this is a, you know, it's a complex issue, and it's hard to -- you can't -- you know, it's hard to boil it down to just these, you know, simple words.

But at the end of the day, you know, using one method or another, you know, over time it results in the same amount of tax paid. It's just really a matter of timing. Do we pay more today and give a loan to the Company and earn interest on that or do we just pay what the Company pays.

Q. Well, and I will agree with you this is a complex issue, and I'd like to direct your attention to the next page of the same exhibit. So that would be 17-12 or page 7 of the exhibit. And the first full paragraph states, "The National Regulatory Research Institute in a study of" this what you referred to as a complex issue "concluded that the phantom tax argument," which is the argument I think we just established you made in your testimony, is quote "oversimplified to the extent it being misleading and fallacious." Do you see that?

A. I do. And the point here is not to say -- so when people talk about the phantom tax argument, they're arguing that there are taxes being paid in rates that the utility never pays, and that's not what I'm saying here. So really it's a timing issue. So do we pay more today and give a loan to the Company or do we just pay what the utility pays.

And so I think while I talk about the growth of deferred taxes and how they never revert, I'm not making this argument that there are taxes being paid into rates that the utility never paid. It's really just a timing issue.

Q. Well, and let me just revert or refer you back to page 74 of your testimony because what I'm hearing you say today is very different than what you put in writing.

So on the top of page 74, on line 1, and this follows on the discussion we already reviewed. It says, "From this perspective, the interest-free loan provided by ratepayers is never repaid. It's continually and constantly refinanced with higher and higher principal balances."

Now, setting aside the fact we already established it's not, in fact, an interest-free loan, your testimony says it's never repaid, which is the misleading and fallacious argument that we just discussed. Now I'm hearing you say something very different. So are you changing your testimony today and acknowledging, in fact, the phantom tax argument does not apply?

A. So unpacking that a bit. So there were a lot of statements made in that that I don't necessarily agree with. So this phantom-tax issue is -- it's the argument that there are taxes paid in rates that the utility doesn't pay, and I'm not saying that.

I'm saying -- the question is -- and I agree completely that there are -- that it's like debt. That these balances grow over time, but because there are new capital additions, they never really reverse.

And so the question here and what I'm saying here is, you know, we're giving this loan to the Company that's never really repaid, and so does it make sense to keep -- for ratepayers to loan this money to the Company, particularly when we're dealing with 23-plus percent rate increases.

Q. Thank you, Mr. Mullins. Let's move on to your net power cost adjustments. So maybe just to get our bearings, if you could turn to page 7 of Exhibit 202. It's your testimony.

A. Okay.

Q. And if we can just look at Table BGM-1.

A. Okay.

Q. This was your initial recommendation, which had a total-Company net power cost of $1.989 billion. Do you see that?

A. I do.

Q. And I understand from the discussion today that you've revised that recommendation, and I believe if I wrote the number down correctly, it's now $2.165 billion; is that correct?

A. Yeah, 2.166 billion. It's possible that I rounded that wrong.
Q. And that was found in the exhibit that was admitted just before your summary that's 212.3; is that correct?
A. Correct.
Q. And just to be clear, the 212.3 presents your adjustments in a very similar way to this Table BGM-1, and in the way that you calculated your adjustments, you performed them sequentially; is that correct?
A. That's correct.
Q. And so, in other words, the valuation of the item on line 6, the DA/RT July Update method in Exhibit 212.3, that valuation presumes you've also previously removed the Washington CCA costs, correct?
A. That's right. That's right. And depending on how the order is performed, it might impact some of the numbers.
Q. Okay. Now, if we could turn back to Exhibit 202 and page 19.
A. Okay.
Q. And the first question on line 2 of that page addressing the system balancing adjustment. Do you see that?
A. Yep.

Q. And on line 10, you refer to that as an "unexplained adjustment." And I believe you said the same thing in your summary this morning; is that correct?

A. Yeah.

Q. And on line 19 you testify, "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 adjustments RMP documented in supplemental direct testimony do not produce the same level of NPC as the final July Update forecast." Do you see that?

A. I do.

Q. Now, Mr. Mullins, you regularly include the same types of balancing adjustments in your testimony in other cases. So let's take a look at a recent example. If you could turn, please, to Exhibit 27. And this is testimony you provided in Portland General Electric Company's general rate case, and it was filed in May of 2023. Do you see that?

A. I do. And you did make a statement earlier that I regularly include this type of adjustment. And so I wouldn't agree with that necessarily, but there are cases when I use a balancing adjustment in presenting, you know, power cost impacts and revenue requirement.

Q. Okay. Well, that's fair. But you agree you do it somewhat regularly?

A. Not necessarily. So, I mean, there's two different ways that you can present an impact study in a rate case. So at least two different ways. So one way is you calculate your adjustments sequentially one after another, and each adjustment afterwards includes the impact of the adjustment prior. The second way -- and so we would call that first way a step change study.

The second way is where you start with the original numbers or the original study, and you make individual changes to that study, and you calculate the impact of each of those changes. And in the end, you combine them all together, and you calculate the total. And because there are -- there will be offsetting relationships between the different adjustments, you include a balancing adjustment to account for the noise.

And so I think the issue here is it's not necessarily that they've done it this way, that RMP has included a balancing adjustment. It's just the, one, the magnitude of it. So $164.2 million is quite a bit of noise in the model.

And then secondly, as I discussed in my summary, they really started from the end result and worked backwards. They didn't start from the initial filing and work forwards. And so because of that, it was virtually impossible to see what was driving that $164.2 million.

So while it is true that I have -- I do commonly use that approach in power cost, not always, I think there's some major distinction with what I'm saying in this testimony between and what, you know, the types of adjustments that I've done in the past.

Q. And just to be clear, in your answer just a moment ago, you said the balancing adjustment is the result of "noise in the model." And, in fact, it's the result of the fact that, when you do sequential studies like you have done, your own testimony in this PGE case says the impacts are skewed by the order in which the adjustments were calculated, correct?

A. So in each one of these studies and each case, you have to exercise judgment about how you present these impacts. So different types of adjustments might impact things differently, and so you may want to present it in a different way.

And in this case, there were actually some very specific reasons with these adjustments for why I presented it this way. And so it turns out in this study there were two specific adjustments that, if you did them together, they resulted in a much larger impact. And so if I were to perform this sequentially, which I had -- usually do for PGE, I'll do a sequential study, but if I had done that, it would have overstated the impact of those individual adjustments. And so I didn't want to present those adjustments as being larger than the impacts that I thought they were. And so that's why I would have -- that's why I did that in this case.

But there are other cases, specifically with PGE, where I've just done sequential studies. So it really depends on the case and the type of adjustments that you're performing.

But at the end of the day, and I think it may be redacted in this, you know, if you're seeing a very large system balancing adjustment, it means that you're not accurately depicting the adjustments up above. And so you need to go back and figure out what's causing that adjustment and explain it.

And so that's the -- I think concern that we had with the update filing is, you know, there's nothing wrong with the system balancing adjustment. It's just that there was no explanation of what was driving it. And trying to work backwards to try to figure that out was virtually impossible.

Q. Now, let's move on to your adjustment for what you call non-native reserves. Now, as a general matter, your adjustment addresses the provision of contingency and regulation reserves that are provided to third-party load and generation that's located within the Company's balancing authority area; is that correct?

A. Correct.

Q. And you agree that the Company is required to provide those reserves pursuant to its open access transmission tariff, or OATT?

A. Yes.

Q. Okay. If you could turn to page 61 of Exhibit 202. That's your testimony. And at the very top, line 6, you testify that "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 a full output of a resource into the market, a resource that's holding reserves must be dispatched down to be capable of responding to such events resulting in an opportunity cost to the utility." Do you see that?

A. I do. And I guess to clarify, it wouldn't just be selling the full output of the resource into the market. It could also be being used to serve customer loads.

Q. And just to be clear, in actual operations, you agree that the Company must hold required reserves in order to comply with its NERC standards, correct?

A. I do.

Q. So in actual operations, there is no opportunity to sell the full output of a resource into the market or to serve customers with that resource if it's holding reserves?

A. I think that maybe the logic there is circular. So here I'm saying if it's not holding reserves, you know, if it didn't have to hold those reserves, it would be able to -- the power costs wouldn't be so high due to its ability to use that resource to serve loads or to sell into the market.

Q. And I guess what I think we agreed on is that the Company's required to hold those reserves, correct?

A. Yes.

Q. And if they are holding reserves, those resources cannot be used to serve customers or sell into the market, correct?

A. I guess that's right.

Q. Now, on that same page 61, if you could go down to line 19, and you say there, "Since the reserve 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 a material cost to RMP." Do you see that?

A. I do.

Q. Now, in order to quantify the impact of that cost that you describe, and I think you said this in your summary, you removed the reserves from the net power cost model, correct?

A. Right. So my recommendation is to use the FERC-approved rates.

Q. Mr. Mullins, I'm just trying to ask you how you modeled it.

A. Right.

Q. We'll get to the FERC issue in a moment, but can you just verify for me that the way that you modeled this cost that you describe on line 21 is by removing the reserve requirements from the model?

A. Right. So the way that I modeled it was I modeled the FERC required reserve requirements in the model using the FERC-approved rates, and I removed the corresponding reserves that were included in the dispatch in the model from the model.

Q. So, in effect, what you did was you allowed the resources that the model was holding in reserve to instead be dispatched into the market or used to serve retail customers, correct?

A. So I -- right. So I guess it's the same statement as before. So I included the FERC-approved costs as the cost, and then I took out the modeled cost because the models cost was several multiples higher than the FERC-approved cost. So we're not saying that those should be removed entirely. We're just saying to limit them to the FERC-approved cost.

Q. Well, and just to be clear, then, what we've established is that, in actual operations, the Company cannot use those resources to sell into the market or to serve load. But your modeling does use those resources to sell into the market or to serve load, correct.

A. So my modeling, as I said, it adds in the FERC-approved cost and removes those reserves from the model. And by doing that, it's including those costs, but then the model is dispatching around the reserves. So I wouldn't necessarily characterize it the way that the question was asked.

Q. Well, just to be clear, when you say "dispatching around the reserves," what you mean is resources that, in the real world, would be holding reserves are, in your modeling, being dispatched so they can sell energy into the market.

A. Right. So the dispatch is complicated. It involves, you know, when you -- and the cost of reserves is equally complicated, but when a resource is holding reserves, it's not able to serve load, and it's not able to sell into the market. So that certainly would be a component of it. However, as a replacement for those costs, we added back in the FERC costs. And so it's not as if there are -- there are no costs of reserves in the model or in my recommendation. It's just that they're limited to that FERC number.

Q. Let's talk about that. So in WIEC 212.3, which is your updated net power cost recommendation, you updated your adjustment such that it's $163 million total-Company or roughly $24 million Wyoming-allocated adjustment. Does that sound about right?

A. Yep.

Q. And, again, this was done sequentially, so the order of the adjustment in all of your adjustments matters, correct?

A. Correct.

Q. So we don't know the true impact of just this adjustment on its own, right?

A. Yeah, I do know that. I mean, it, of course, depends on, you know, a lot of things.

Q. And what are you looking at? Is this in the record?

A. These are just my notes, so if you're --

MR. WILLIAMS: Mr. Lowney, I apologize for interrupting, but it is eleven o'clock. If we could take a pause.

MR. LOWNEY: Yes.

MR. WILLIAMS: At this point I do believe we have one public commenter at least on Zoom. So let me at least ask in the room, is there anyone here who would like to make a public comment at this time?

Let the record show no response.

Mr. Phetteplace, I believe Mr. Deny felled der is online.

MR. PHETTEPLACE: Correct. I just now sent him the request to unmute.

MR. DEGENFELDER: Good morning. Am I on the line?

MR. WILLIAMS: You are, sir. Would you please, sir, state and spell your name for the record.

MR. DEGENFELDER: Yes, for the record, my name is Steve Degenfelder. That's D-e-g-e-n-f, as in Frank, e-l-d-e-r.

MR. WILLIAMS: And sir, you are a customer of Rocky Mountain Power?

MR. DEGENFELDER: Yes, I work for a company that is a customer of Rocky Mountain Power.

MR. WILLIAMS: Please proceed with your statement.

MR. DEGENFELDER: Thank you. Good morning, Chairman Throne, Deputy Chairman Petrie and Commissioner Robinson. Thank you for the opportunity to make public comment on this very important issue. My name is Steve

Degenfelder. I work for Kirkwood Oil & Gas, LLC. It's a private family-owned company in business since the 1960s. Besides developing new exploratory prospects in the state, the Company's operating affiliate also operates about 300 oil and gas wells in Wyoming and has a monthly electric bill of $315,000.

While most of the discussion about this case is centered around what it will mean to residential rates, I am here to ask you to pay careful attention to what the rate increase will do to small and midsize industrial ratepayers like Kirkwood.

The largest oil and gas producers are represented by the Wyoming Industrial Energy Consumers, and we certainly appreciate and support their work as intervenors in this case. However, there are hundreds of smaller oil and gas producers in Wyoming just like Kirkwood. The average production of our wells is less than 5 barrels per day per well. That doesn't sound like very much, but in 2022, the Company paid over $7 million in royalties, severance taxes and ad valorem taxes to the state and various counties in Wyoming.

While we do not have the scale of larger operators, make no mistake that, just like them, power costs make up a very significant portion of our cost of doing business. In fact, I'd wager that, as a percentage of our operating margin, power costs are more significant for us small operators.

A 30 percent increase will inevitably put pressure on our end-of-life wells and could very well make them uneconomic requiring them to be plugged and abandoned.

Let me be clear, when those wells are plugged and abandoned, the associated royalties, severance taxes and ad valorem taxes I previously stated that would be paid will also go away.

This increase for Kirkwood is material and means we are going to have to make tough decisions about future investment in oil and gas projects. Oil and gas is a primary economic driver in Wyoming, and small operators like us are a big portion of that economy. If we are forced to manage a 30 percent increase in power costs, the consequences will go well beyond just our business.

The proposed increase by Rocky Mountain Power appears to be related to increased fuel costs and demand-related third-party power purchases. Everyone is aware of inflation and natural gas price spikes we saw at the end of 2022 and the beginning of 2023. Rocky Mountain Power is currently recovering the increased fuel costs through their 7 percent cost recovery that came into effect in July 2023. Natural gas prices have dropped in the latter part of 2023, and the differential prices seen for gas going west has gone down.

The law requires rates to be just and reasonable. A 30 percent rate increase on Kirkwood is not just or reasonable.

For the reasons stated above, I respectfully request that the Commission approve a lower rate of increase more in line with the national inflation rates of 8.8 percent in 2022 and 6.6 percent in 2023.

Thank you for the opportunity to address and make comments to the Public Service Commission on Rocky Mountain Power's proposed rate increase and its actions on Kirkwood Oil & Gas. Thank you.

MR. WILLIAMS: Thank you, sir.

Are there any other individuals on the Zoom Link who would like to offer public comment?

MR. PHETTEPLACE: No raised hands.

MR. WILLIAMS: Thank you.

DEPUTY CHAIRMAN PETRIE: Mr. Williams.

MR. WILLIAMS: Yes.

DEPUTY CHAIRMAN PETRIE: I'd like, if you might, to ask Mr. Degenfelder the source of the inflation numbers that he just cited.

MR. WILLIAMS: Certainly. Mr. Degenfelder, are you there?

MR. DEGENFELDER: Yes, I'm here.

MR. WILLIAMS: Did you hear the Deputy Chairman's question, sir?

MR. DEGENFELDER: Yes, that figure was given to me by one of our petroleum engineers. I can chase down the exact source of where he got that figure.

MR. WILLIAMS: Are there other questions from the bench for Mr. Degenfelder?

CHAIRMAN THRONE: Could we ask if all of his wells are in Rocky Mountain territory?

MR. WILLIAMS: Did you hear, Mr. Degenfelder? Are all of your wells in Rocky Mountain territory?

MR. DEGENFELDER: Madam Chairman, no. Some of ours are through the local REAs, but we fully expect with these cost increases that we'll see those with the local REAs as it's worked its way through.

CHAIRMAN THRONE: Thank you.

MR. DEGENFELDER: But not all the wells are under Rocky Mountain Power.

MR. WILLIAMS: Any other questions?

Thank you, Mr. Degenfelder.

MR. DEGENFELDER: Thank you.

MR. WILLIAMS: Mr. Phetteplace, has anyone else raised a hand at this point?

MR. PHETTEPLACE: No raised hands, sir.

MR. WILLIAMS: Thank you.
Mr. Lowney, please proceed.

CROSS-EXAMINATION RESUMED

Q. (BY MR. LOWNEY) Okay. Well, Mr. Mullins, let's use the $163 million figure you include in the record as the valuation for your adjustment. And you agree that the Company recovers roughly $12 million total-Company for the provision of reserves under its OATT rates; is that correct? I can direct your attention to page 63 of your testimony where you have that quantification.

A. Yeah, that is correct. And yeah, $12.2 million, and in preforming our adjustments, we removed the reserves that were modeled in Aurora, and we added back that cost, those revenues as the cost of reserves. So we're tying back to the FERC-approved rate.

Q. Well, that's what I'd like to talk about. So just to get our math right, and again, I'm rounding, but the difference between the $163 million calculation you make and the $12 million OATT rates is about $151 million rounded, correct?

A. No. Because the 166 is net of the $12.2 million. So my study -- so if you were to not include the $12.2 million, it would be about 175 million. So the model impacts are higher than the 166.3.

Q. So the gap, then, is $163 million.

A. Right. Exactly, between the forecast costs, which were about 175, and the additional cost to cover the revenues, which were added into the forecast.

Q. Okay. Now, if we could turn to page 65.

A. Okay.

Q. On line 8 of your testimony, you testify that "...the costs of serving non-native loads and resources should be paid for by those loads and resources," correct?

A. Sorry, what was the line?

Q. Line 8. "...the costs of serving non-native loads and resources should be paid for by those loads and resources." Do you see that?

A. Right, as a general principle.

Q. And a little further down on line 13 you refer to these as "revenue shortfalls." Do you see that? And that was also the word you used in the table we were looking at on page 63 of your testimony, Table BGM-3 referred to as a revenue shortfall. Do you see that?

A. Right. So the revenues from the OATT rate do not cover the cost of serving those customers as measured by Aurora. So the cost is about $175 million versus the $12.2 million. And so the revenue shortfall I'm referring to there is the difference between those two values.

Q. And on line 14 of that same page 65, and I'll paraphrase here, but you basically say, if the OATT rates are inadequate to recover that revenue shortfall, the Company should go to FERC and fix its rates. Is that a fair summary of that testimony?

A. I might not say "fix its rates." I think this speaks for itself.

Q. Okay. Well, just to be clear, then, implicit in your adjustment is a request that this Commission determine that the FERC rates are unreasonable and don't reflect the true cost of providing reserves; isn't that right?

A. No, I think exactly the opposite. So I'm actually using the FERC cost as the cost of reserves.

Q. But I think you just said in your testimony, "If the FERC-approved rates are inadequate to recover the costs of serving non-native customers, it would be appropriate for RMP to seek to recover those funds through its FERC rates."

A. Yeah. I --

Q. Doesn't that mean the FERC rates are insufficient to recover the costs as you've calculated them?

A. I think that would be a determination for RMP to make. I think, as we look at this case, however, the costs that are being proposed in net power costs are an order of magnitude higher than the costs that FERC calculates. And so, you know, to the extent there's -- you know, those FERC rates are -- if PacifiCorp finds them to be inadequate, then I think that's something they would need to address.

Q. Well, just to be clear, Mr. Mullins, you found those FERC rates to be inadequate because your testimony is that there is a $163 million difference between how you calculate the cost of reserves by removing them from the model and the way FERC calculates the cost of reserves under its OATT rates, correct?

A. I wouldn't say it that way. I mean, I think the Aurora model, the way that PacifiCorp has configured it, is including much more costs than the FERC rates. And so, you know, I'm not making any judgment on how those FERC rates are calculated, but rather, saying that, you know, the costs included in rates are limited to what's recovered and the costs that FERC determines.

Q. And so essentially, then, what you're saying is that the Commission should set retail rates as if the Company were receiving significantly more revenue for the provision of reserves than it is currently authorized by FERC, correct?

A. Yeah, I probably wouldn't say that again. I think my recommendation speaks for itself. My recommendation is to include only the FERC-approved costs and nothing more. The way that the model is configured it has -- you know, there's much higher costs being included in NPC, and I don't think that Wyoming customers should be required to subsidize non-owned third-party, you know, wind and loads.

Q. And so, again, that subsidy can only happen, though, if there's a finding that the FERC rates are insufficient to cover the cost of reserves as you've calculated them?

A. I mean, I think it would be an insufficiency maybe in the modeled costs. I mean, we're seeing in the model there's quite a bit higher costs. So I think if PacifiCorp thinks that that cost is there, then I think it's between them and the FERC to try to recover those costs. But I don't think that Wyoming customers should be kind of in the cross-hairs of that particularly when we're dealing with such a large rate increase.

Q. Now, Mr. Mullins, are you familiar with WIEC witness Mr. Higgins and particularly his testimony relating to energy cost adjustment mechanism or ECAM?

A. You know, I didn't review that in detail, and I'm not the witness for that.

Q. Well, let me just ask you, would you agree that one of the purposes of the ECAM is to set an accurate net power cost forecast?

A. I don't think -- I don't know that's the purpose of the ECAM itself. I mean, I think I would probably defer to Mr. Higgins on what the purpose of the ECAM is. I certainly think that that's an important consideration, but I wouldn't say that's an ECAM purpose necessarily.

Q. But you would agree, I guess, generally the net power cost forecast should be set as accurately as possible, and to be an accurate forecast, it should reflect actual operations, correct?

A. So the forecast should be accurate and from a normalized basis. So, you know, when you set the net power cost level, I think we recognize that there may be some years when it's higher, some years when it's lower, and so really the idea is to strike that balance.

And I'm sorry, I forgot the second part of your question.

Q. Well, would you agree that an accurate forecast should track actual operations? In other words -- let me restate that. It's a poorly way to say it.

In order to produce an accurate forecast, that forecast should reflect actual operations. Wouldn't you agree?

A. I think at the end of the day we're mostly concerned about the costs and the prudently incurred costs. And so to the extent that coal plants dispatch more or less or there's more sales than purchases, if we can get the cost values right, I think that's a higher consideration than going into the model and seeing whether individual plants perfectly operated in the future the way that we thought that they would have.

Q. Well, I guess what I'm asking you is do you think that the forecast should reflect actual operations in the general assumptions that are used to either craft an input or to design and operate the model?

A. So as a general principle, we do design the forecast around the actual capabilities and -- or actual expectations of how those plants will dispatch and things, but at the end of the day, it's really the costs and the baseline that matters.

Q. Now, I'm going to ask you another question about the ECAM, and I understand if you can't answer it. But would you agree that Mr. Higgins testifies that one of the purposes of the ECAM is also to create an incentive for the Company to control its costs in actual operations?

A. I think I would defer to Mr. Higgins on that.

Q. Now, setting aside that deferral, would you agree that in order for the Company to realize the net power cost savings included in your adjustment, the Company would have to stop holding reserves that are required in order to ensure a reliable system?

A. I'm sorry, could you repeat that.

Q. In order to realize the cost savings that your adjustment assumes, the Company will be incented to stop holding reserves that it is required to hold in order for the system to remain reliable.

A. Okay. So a couple of things. So, first, it's not really cost savings. So we're -- as I mentioned, we're just limiting the costs included to what the FERC rate is. And we're not necessarily saying that they're not going to hold those reserves, but just that the costs included should be limited to what, you know, what FERC approves.

And as far as, you know, dealing with that in the ECAM and actual operations, it's something I have thought about some, but I think those would be details that we would need to work through going forward.

Q. Well, and just to be clear, though, the way you calculated your cost savings, the reduction to net power cost was by removing the reserves from the forecast, letting those resources being sold into the market or used to serve customers, correct?

A. I think this will go back to kind of the sort of repeating response that we initially took those reserves out, but then we added back the FERC-approved costs for those reserves into the model. So it's not as if there are no reserves in the model.

Q. Well, just to be clear, you've added back the costs, but the model is dispatching resources that in actual operations cannot be dispatched, and that's how you're achieving the savings that you include your adjustment; isn't that right?

A. Not necessarily. So by adding in the costs, there are -- implied in that there are the system costs of those reserves. So while that's not in the Aurora model, per se, it is implied in the costs that are being added back in.

Q. So the model is holding reserves back? In other words, it is not freeing up resources?

A. So, as I mentioned, so that would be implied in the costs that are added back in. But when you remove those reserves from the Aurora model, it does re-dispatch around those and either use them to serve loads or to reduce purchases is another area where it impacts it or to make sales, but then we add back in the FERC-approved costs. And so that correspondingly eliminates those -- the ability to make sales and purchases on that amount.

Q. Okay. Mr. Mullins, let's move on. In your summary, you made reference to a recent -- well, recent, last Friday order issued by the Public Utility Commission of Oregon in the Company's 2024 transition adjust mechanism or TAM proceeding. Do you recall that?

A. I do.

Q. Now, you were a witness in that case; isn't that right?

A. I was.

Q. And Exhibits 21 and 22 in this case is your testimony from that case; is that correct? Have you looked at those exhibits? It's filed on behalf of the Alliance of Western Energy Consumers. And maybe we'll turn to Exhibit 21 first just to get our bearings. This was your open testimony that was filed on June 23rd of 2023. Do you see that?

A. Okay.

Q. And then Exhibit 22 is your rebuttal testimony which was filed on August 16th. Do you see that?

A. I do.

Q. And just for context, your testimony in this case was filed on August 14th. So two days before this Oregon testimony was filed; is that correct?

A. That is correct.

Q. Okay. If you could turn to page 4 of Exhibit 22.

A. Okay.

Q. And that table, which is Table 1, is your recommendation in the TAM for the net power cost adjustments, correct?

A. Correct.

Q. And if we just compare that to the same table on page 7 of your testimony in this case.

A. Okay.

Q. My apologies if we have to flip back and forth. I'd just like to identify the similarities between those two tables. Are you at -- do you have in front of you -- I apologize we're going to have to flip back and forth a little bit between Table BGM-1 on page 7 of your testimony in this case and Table 1 on page 4 of Exhibit 22.

A. All right. Okay.

Q. And just looking at those two tables, they're fairly similar, correct?

A. Yep.

Q. In fact, even in your Oregon testimony, you refer to the RMP July Update; isn't that right?

A. In that the -- sorry, which exhibit? The 202?

Q. Exhibit 22. This is your Oregon testimony, but you make reference to RMP on line 1 of Table 1.

A. Right, yeah. So that was a typo in that case.

Q. And just to be clear, if we flip back to your Wyoming testimony in this case, Table BGM-1 has total-Company net power cost forecast of $1.989 million, which has subsequently been increased in WIEC 212.3, correct?

A. Yep.

Q. To $2.166 million?

A. Yep.

Q. All right. And then in your Oregon testimony, your NPC adjustments resulted in a forecast for 2024 of

$2.197 million rounding, correct?

A. That's correct.

Q. So your Oregon recommendation was higher than your recommendations in this case, right?

A. So that's correct. And the big difference is the non-owned wind, or sorry, non-owned reserve issue. So that wasn't included in this testimony. So that was kind of a new issue that I became aware of after filing testimony in Oregon. And so that's the driver of the difference between this. And there are some other differences between this and my direct testimony in this case.

Q. And just to be clear, as we look down the number, or excuse me, the name of the adjustments included in the Oregon case, they're very similar. You have an adjustment for the modeling environment of Aurora. You have market caps adjustments. You have DA/RT adjustments. You have the Ozone Transport Rule.

A. Right. And one clarification is there's another typo in this testimony that the market caps 95th percentile was actually a different adjustment. So that was -- it was a specific method that the Oregon Commission has used in the past, and so and I clarified that in the hearing in that case.

Q. Thank you for that clarification.

And I would actually like to ask you about that hearing. So just so the record is clear, there was an evidentiary hearing in that TAM docket on September 7, 2023, correct?

A. Correct.

Q. And during that hearing, you and I did much like we're doing today; isn't that correct? You were cross-examined; is that right?

A. I was cross-examined, that's correct.

Q. Okay. Now if we could turn to Rocky Mountain Power Exhibit 13.7.

A. Okay.

Q. And this exhibit is an excerpt from that hearing, and it's an excerpt that is the entirety of your cross-examination testimony.

A. Okay.

Q. Now, during that cross-examination, you and I discussed your DA/RT adjustments, correct?

A. Correct.

Q. And if we could turn to page 26 of that exhibit, beginning on line 3, there's a question that says, "Just to be clear, though, your recommendation is based on modeling results that we are describing that, if I'm understanding correctly, you are admitting are erroneous or unreliable; is that correct?"

And your answer was, "No, no, I think -- what?

Well, I actually don't know." Do you see that?
A. Yeah. So and then I go on to explain that I need to go back and double-check what was happening. So this was a specific issue in the Oregon TAM case, not completely unrelated to this case in which some of the sales, purchases and sales in my NPC forecast were being -- dollars were being inflated. It had no impact on overall NPC. And so I did go back and check what was causing that. And in this case in our errata, which I don't know the exact date that it was filed, we made a correction to make sure that that was -- to correct that to eliminate those sales -- purchase and sales values.
Q. And just to be clear, you never corrected your Oregon testimony, did you?
A. No, we didn't. I mean, it was after the hearing. So we did not correct that.
Q. And just to be clear, while the Climate Commitment Act issues you described in your summary were litigated in that case, the Oregon Commission also approved the baseline net power costs that would be used for 2024 in that case as well, correct?
A. So in that case there was a settlement. It was with Rocky Mountain Power or PacifiCorp, also Rocky Mountain Power. And all of the parties except for AWEC, the customer group that I represent, and in that settlement

PacifiCorp agreed to reduce Oregon-allocated net power costs by approximately $18 million, and that included the effects of removing the Utah Ozone Transport Rules. And on a total-Company basis, if my recollection is correct, that resulted in a net power cost of $2.46 billion, and that did not include the impacts of the CCA, which we discussed the Oregon Commission ultimately declined to approve. And so that reduced that forecast down to approximately 1, or sorry, approximately 2.40 billion.

And then another thing to point out is that in net power costs in Oregon, the Rolling Hills wind plant is not included, and that's an approximate 10 to $20 million difference between the NPC in Wyoming and the NPC in Oregon.

And so to compare sort of that outcome in the stipulation to this case, we would be looking at a 2.38 to $2.39 billion net power cost. And recognizing there's lots of give and take that goes into that.

And ultimately the Commission in the Oregon case, they didn't decide really on any of the issues. They just accepted the stipulation and found it to be reasonable. So I think that's sort of the crosswalk between that case and this case.

Q. I appreciate that you're acknowledging the Oregon net power costs are higher than your recommendation here.

But just to confirm, AWEC, the Alliance of Western Energy Consumers, challenged the stipulation, and according to the order, did so specifically based on your DA/RT adjustment recommendation; isn't that correct?

A. Right.

Q. If you'd like, you can turn to page 5 of the order, which is WIEC Exhibit 241.

A. So that I think is generally correct. So the -- I guess the nature of the opposition to the settlement was that it didn't -- it included part of the modeling change that we discussed earlier, and we didn't think that that was reasonable in light of the way that the Oregon update process works as well as changes to the market caps.

And so -- and I wasn't involved in sort of contesting that settlement, but in terms of opposing it, you know, those were our issues. And, of course, the other parties, you know, were willing to sort of negotiate on those issues. But from my perspective, you know, introducing that new DA/RT modeling adjustment in the middle of the case wasn't something that I was comfortable supporting or nor my customers.

Q. And just to be clear, I think you already said this, but the Commission did not adopt any of your adjustments in that TAM, correct?

A. Sorry. The Commission didn't decide on any of the adjustments. They just found that the stipulation was reasonable. So they didn't consider any of the merits of those adjustments.

Q. Now, let's turn -- I just have a few more questions on the Climate Commitment Act. Now, in this case you recommend that all of the cap and invest costs associated with the Climate Commitment Act should be situs assigned to the Company's Washington customers, correct?

A. Not necessarily. So, I mean, I think from this case we're just looking at it from Wyoming's perspective. It's a complicated issue, and at least from Wyoming's perspective, given that Washington state receives, you know, free allowances for their customers, we don't think that Wyoming customers should have to pay for that policy.

Now, I think as far as how we deal with that going forward, especially in Washington and within the broader multistate process, is I think something that we really need to consider.

And in Washington, I filed testimony on behalf of a customer group there, AWEC also, and I pointed out to the Commission that we need to come to figure out a solution to this problem because it's not workable for Wyoming. It's not workable for the Company. It's not workable for the customers, and so there needs to be some solution. But for this case today, I think the decision really has to be that it's not included in rates.

Q. And just to be clear, in that Washington testimony, you did not recommend that Washington customers pay the cost of the Climate Commitment Act, did you?

A. So I did not propose a situs assignment-type adjustment in that case. But I did recommend that the Commission come to the multistate process and come up with a solution for the Company and for customers in the other states.

Q. And the specific solution you recommended was that Washington pursue inclusion of all of the costs and benefits of Chehalis exclusively of Washington rates; isn't that the recommendation you made in your Washington testimony?

A. I'm not sure that I said it that way. But I did -- I do think that one possible option is for Washington to sort of take full -- take on 100 percent of Chehalis.

I think it's a complicated issue because, you know, sort of carving a single resource out of customer rates gets very complicated very quickly, and so I think that's one possible solution. It's not the only solution. But at the end of the day, we really should have been having these conversations a year ago or two years ago when this legislation was coming out, because trying to deal with this after the fact, it puts really everyone, the Company, the Commission in a very difficult place.

Q. And just to be clear, your recommendation in this case is not to remove Chehalis from Wyoming rates, correct? In fact, WIEC opposes that position; isn't that true?

A. Right. Yeah, so, yeah, we don't think -- wouldn't think it would be appropriate to remove it, remove it from rates.

Q. And in your Oregon testimony that we were just discussing in the transition adjustment mechanism docket, you also didn't recommend situs assignment to Washington of costs resulting from the CCA, correct?

A. So my -- yeah, so my testimony in Oregon was like this testimony focused more on sort of the -- sort of the discriminatory nature of the Cap and Invest Program and not necessarily on the multistate process, interjurisdictional allocation issues.

The Commission in Oregon, however, was very clear about how that should be done and that it should be situs assigned and so right. And the Oregon staff as well made that recommendation. But that wasn't specifically in my testimony. I talked about mostly the discriminatory issues.

Q. Now, Mr. Mullins, in your summary today, you said -- and I'm going to try to quote it, although I'm sure

I'm paraphrasing, that the CCA is not a tax. It's a policy. Do you recall that language in your summary?

A. I do.

Q. Now, if you could turn to Exhibit 21, please. And, again, this was testimony that you filed in that TAM docket. And if we could go to page 14 of that testimony. Or excuse me, 14 of the exhibit.

A. Okay.

Q. Now, you're discussing the CCA on this page of your testimony. And on line 9, you specifically refer to it as a generation tax. Isn't that correct?

A. So this is a general statement. So I say, "Complex legal issues arise with respect to the imposition of generation taxes and regulations that impact interstate commerce." And then I go on to state that these issues will not be addressed here.

And so basically what I'm saying here is that we're going to address these issues in briefing. And, you know, I'm not a, you know, constitutional law expert by any means, but I do understand that there are differences between taxes and regulations, and so I think that's what I'm saying here is taxes and regulations, not necessarily referring to the CCA as a tax per se.

MR. LOWNEY: All right. Thank you. I have no further questions.

MR. WILLIAMS: Thank you.

Miss Monahan, do you have questions of this witness?

MS. MONAHAN: No questions. Thank you.

MR. WILLIAMS: I'm assuming no raised hands from Senator Case or Mr. Flege.

MR. PHETTEPLACE: There are none.

MR. WILLIAMS: Miss Hamilton, do you have questions?

MS. HAMILTON: No questions. Thank you.

MR. WILLIAMS: Mr. Petrisin.

MR. PETRISIN: Yes, sir.

MR. WILLIAMS: You do. Mr. Petrisin, we'll pick up with you after lunch. We'll take a recess now. We'll reconvene at 2 p.m. this afternoon. The Commission is convening in open meeting at 1:30. So enjoy your extra long lunch, although some of you from Rocky Mountain Power will need to be here at 1:30 for the open meeting.

(Hearing proceedings recessed
11:44 a.m. to 2:00 p.m.)

MR. WILLIAMS: Good afternoon. It's 2 p.m. We are back.

Mr. Petrisin, you had questions for Mr. Mullins?

MR. PETRISIN: Yes, sir.

EXAMINATION BY THE COMMISSION STAFF

Q. (BY MR. PETRISIN) Hello, Mr. Mullins.

A. Hello.

Q. Were you listening to the questioning of Mr. Mitchell on Friday, October 27 2023?

A. I was not.

Q. I'll get you up to date. During that questioning, Chairman Throne asked a question about the system balancing impact of adjustments. Mr. Mitchell began his answer as such: "I'll try my best, Chair. So I'll first say that the line item titled 'System Balancing Impact of Adjustments' is unnecessary and irrelevant to the net power cost proposal and unnecessary and irrelevant to the net power cost impacts of the various changes. It's purely an accounting entry to help the reader, and I guess in some cases it confuses the reader." Would you agree with that statement?

A. Maybe parts of it. So the system balancing adjustment is -- it's really the difference between the sum of the individual adjustments and the total NPC that they calculated. And in their case, I think I mentioned this earlier, but they kind of started with the end results, kind of the end study, and actually worked backwards to try to figure out the impact of most of the changes that they made.

But by doing that, you know, there were impacts that either were offsetting and that impacted each other that weren't, you know, properly, I think, documented in that approach. So I think if you're seeing a system balancing adjustment that large, it would mean that some of those adjustments or the impacts are not being accurately depicted. And so that's why I went through sort of a sequential study is to do a calculation where the actual impacts are more accurately shown.

Q. That actually answered my second question. Thank you.

A. Okay. Thank you.

MR. WILLIAMS: Commissioner Robinson.

COMMISSIONER ROBINSON: No questions. Thank you.

MR. WILLIAMS: Deputy Chair.

DEPUTY CHAIRMAN PETRIE: Thank you.

EXAMINATION BY THE COMMISSION

Q. (BY DEPUTY CHAIRMAN PETRIE) Mr. Mullins, are you suggesting that Rocky Mountain Power could or should ignore any reserve obligations that it currently has or has in the future?

A. I'm not. So my recommendation is primarily on the impact to net power costs associated with those reserves and comparing the impact and the costs that FERC allows to be recovered and the costs included in the Aurora model. So we're not saying that they shouldn't or won't be holding those reserves.

Q. And then regarding the discussion of the phantom tax, so-called phantom tax argument, and the Company has strongly suggested that this has been discredited by both the Federal Energy Regulatory Commission and the NRII. And so my question is can you distinguish the situation that we face here in this general rate case from what I take is the general conceptual objections to that treatment that you propose that the Company has pointed out in the literature?

A. Yeah, absolutely. So the concept of a phantom tax is it's implying that there are taxes that the utility is recovering that are never paid. And so that's not what I have proposed, and if my testimony came off that way, it wasn't intended to mean that.

The issue here is it's really more of a timing issue. So whether you use normalization or flow-through accounting over, you know, the period of time the utility is going to collect all of the taxes that it pays out under either method, it's just whether you spread out those tax benefits of accelerated depreciation over the life of a resource or if you recognize them when they are received. And I say accelerated depreciation because that's probably the principal driver of the deferred taxes and the difference.

And so one of the reasons why that makes sense is those tax benefits occur in the early years of a resource's life, and those are the years when the resource is actually more expensive. So while it's true that later in that resource's life customers will be benefiting from that resource, the cost then is otherwise smaller because the plant would have depreciated.

So doing it this way I think is appropriate, and it -- I guess there's also this issue of whether it's a stable calculation, whether it might vary year to year, and that -- you know, for purposes of ratemaking, we're dealing with normalized revenue requirement. And so to the extent that, you know, like major plant goes into service, that's going to add lot of costs into revenue requirement. But then there's also going to be those tax benefits to offset that early cost. And so over time that benefits ratepayers, I think, at least temporally so that it's allocating that cost fairly.

Q. Let me see if I understand that. Are you suggesting that while in early years there would be an advantage to then current customers, the effects of the depreciation of the plant would balance that in the later years of that capital's service life or --

A. Yeah.

Q. -- depreciation life?

A. Yeah, so over time it will result in slightly lower costs in the early years when that plant balance is high and ratepayers are paying more, but in the later years, there won't be that benefit when the plant balance is otherwise lower. And, of course, in that later period there will be new capital additions being made, and so those customers will benefit from the new capital additions just as the earlier customers benefitted from the capital additions that were made at that time.

DEPUTY CHAIRMAN PETRIE: Thank you.

MR. WILLIAMS: Chairman.

CHAIRMAN THRONE: Thank you, Mr. Williams.

EXAMINATION BY THE COMMISSION

Q. (BY CHAIRMAN THRONE) Good afternoon, Mr. Mullins.

A. Good afternoon.

Q. Nice to see you here and not some weird hour of the day.

A. I do appreciate the chance to be here.

Q. As you began your testimony, you made some general comments about the Aurora model, and I want to make sure I heard them correctly. So I believe you stated that you have been using the Aurora model since about 2014?

A. Yeah.

Q. And then you went on to say that it's different than the GRID model, and the Aurora is not really designed for the purposes that it's being used for here?

A. Yeah.

Q. I also heard you say that you're not aware of any other utility in the West using it in the same way as Rocky Mountain Power is.

A. Yeah.

Q. So I heard all of those things correctly?

A. Yeah. Would you like me to expand on those?

Q. Sure.

A. Yeah, absolutely. So my focus and the customers I represent are predominantly in the West, so that's why I mentioned the West there. And there are many utilities, particularly in the Northwest, that have used Aurora for a long time. So Aurora was actually developed by a -- some former employees of Portland General Electric Company. They went off, and they developed the software, and then companies like Avista and Puget Sound Energy, Idaho Power, they all started using this for price forecasting and for ratemaking purposes.

So in the -- the way that the Aurora model was originally developed, it was a -- it's a WECC-wide model. You know, have all of the resources for every utility in the WECC and all of the loads in the WECC, and there will be particular, you know, market zones, and it will figure out, based on the generation stack, what the relative -- the relationship between the loads and the generation resources are. And based on the marginal generator in that stack, we'll say that this is the market price for this particular market area.

And so it's a regionwide dispatch, and utilities like Avista were using that regionwide dispatch and saying these are our specific resources in that regionwide dispatch, and so this is how they would have dispatched in that total portfolio.

And so, yeah, so I've reviewed those for Idaho Power, Avista, Puget Sound Energy. Portland General actually is a different power cost model, but they do use the Aurora model for price forecasting.

So the -- right. So PacifiCorp in -- I think it was maybe around 2013ish actually underwent a process through Washington to try to use the Aurora model to forecast power costs. They were directed by the Washington Commission, which was familiar with Aurora to do this. And at the end of that process, they were unable to get that regionwide dispatch to do the same things as the GRID model was doing.

And a lot of it has to do with the complications of PacifiCorp's transmission system as well as the fact that the Aurora model, it doesn't -- it doesn't have an ability to do off-system sales. So the GRID model, it included off-system market sales as one of the things that went into the optimization. So the Aurora model didn't do that.

And what PacifiCorp has done in this new model is it's actually quite a good sort of technique, but they've tried to simulate these off-system sales using loads and resources that offset those loads. So it's sort of this resource and then offset kind of concept. And it's a good technique, but I'm not so sure that all of the effects of that have been ironed out, and so there may -- some of the things I've seen in Aurora make me question how that's working.

At the end of the day, I think, you know, it's besides that contingency reserve issue that I noted, I think I'm comfortable with kind of the forecast results, but I think going forward there might be some refinements that could be made.

Q. And going back to the system balancing adjustment, I think there was a follow-up question that I asked Mr. Mitchell, and I essentially asked him, as I recall, is if you're doing those deductions adjustments sequentially, is there a risk that you're double-counting, and I believe he responded that he agreed with me.

So is that the reason for the system adjustment, in your opinion, is to avoid double-counting?

A. Well, it can -- it can -- you know, two adjustments can amplify each other. And this was in the PGE case that I filed testimony in earlier this year where there was one adjustment for heat rates and another adjustment for the unit capacities. And when you looked at them in isolation, they were actually smaller than the combined whole.

And so because of that, the total impact of when I combined them was larger, and so I didn't want to give the impression that they were larger than they actually were, which is why I had done it sequentially.

But if it's done sequentially, you could never -- it could never really -- I shouldn't say never, but usually you won't see it double-counting things. So if you do it as a one-off study where you're just starting from the base and making many changes and then doing the system balancing adjustment in the end, there is the possibility that two adjustments can address the same costs, and so you're double-counting those adjustments.

So like, for example, when they sort of criticized my testimony on this, they said, oh, if you do -- PacifiCorp or RMP said, "Oh, if you run Mr. Mullins' adjustments in the same way, it would result in a big system balancing adjustment."

Well, the reason for that was because the two different DA/RT adjustments that I had performed were overlapping. So if you go -- if you go back to the average or just simply tie to the average DA/RT impacts historically or if you reject the -- it implicitly rejects the change that was made in the July Update. So both of those adjustments would have captured the same costs. So if you don't do one and then the other, it's going to inaccurately show those adjustments.

So there is kind of some judgment involved in how you present those, but in the bottom line you do want to, you know, minimize what that system balancing adjustment is so that you can explain everything that's happening in the study. And it might mean, for example -- and I've seen this done in the past. You might do a hybrid between the two. So you might say, "All right, so we're going to do market prices first because that impacts a lot of things, and then we're going to do these one-off runs from a study that includes market prices."

So there's no like one right way to do it, but if you're seeing a large discrepancy, it means that there's something you need to look into.

Q. Okay. Thank you.

And I think I have one final question about the reserves. So is it your testimony that the Aurora calculation is overpricing those reserves for purposes of net power costs, if I'm not oversimplifying too much?

A. Yeah. No, that's -- I think that's actually a good question. So, in part, so it's definitely overpricing contingency reserves because of sort of that error that I discussed in my intro where you can either toggle off the reserves or you can remove the resources.

And I think it's pretty apparent from the July Update that there was a correction to contingency reserves, and that actually increased net power costs by $63 million compared to I think it's about $5 million in revenues for all contingency reserves. So there's a really big discrepancy there.

You know, for the remaining costs of reserves, you know, I think that getting reserves right in these models is actually very difficult. And so I think that the Aurora model probably does overvalue those reserves based on the costs relative to the revenues. But at the end of the day, reserves are very expensive. And if -- you know, if there is an opportunity cost associated with those reserves, I'm not sure why Wyoming customers have to pay that opportunity cost.

CHAIRMAN THRONE: Thank you.

THE WITNESS: Thanks.

DEPUTY CHAIRMAN PETRIE: That's all.

MR. WILLIAMS: Mr. Nelson, do you have redirect?

MR. NELSON: Yes.

REDIRECT EXAMINATION

Q. (BY MR. NELSON) Mr. Mullins, just a couple of questions for you from the cross-examination.

Okay. Can you please open Exhibit Number 37.

A. Okay.

Q. Do you recall a series of questions that you discussed with Mr. Lowney regarding the tax issue and what has been -- what was described in this Exhibit 37 as the phantom tax argument? Do you see that?

A. I do.

Q. Do you recall that? Sorry.

A. I do.

Q. Okay. I want to call your attention to page 6 of that document.

A. Okay.

Q. Okay. And I want to focus on the discussion here on page toward the bottom. Do you see there where it has a sentence that says, "The fundamental fallacy inherent in the phantom tax argument has been succinctly stated by the FERC"? Do you see that, sir?

A. I do.

Q. So we're going to go through these two paragraphs here real quick, and then I want to talk about how this discussion relates to your testimony.

So the document says, "A final important concept relating to the issue of timing differences and interperiod tax allocation is that of continual tax deferral. This is associated with the composite effects over time of a combination of timing differences affecting a company. A continual tax deferral arises when, over time, the total tax benefit associated with new timing differences equals or exceeds the total value of the reversals occurring from earlier timing differences. As a result, under a normalization policy, a positive balance of accumulated deferred taxes reflecting the collection of more taxes in rates that have been paid by the Company could exist into the foreseeable future." Do you see that?

A. I do.

Q. Does that discussion here -- when you answered Mr. Lowney and other questions and spoke to a concern about the timing differences raised between the flow-through and normalization method, does that paragraph capture what you were referring to?

A. Yeah, that's right. So over time, as new capital is added using the normalization method, the tax, deferred tax balances continue to grow over time and don't reverse.

Q. And is that dynamic driven when the utility in question is increasing its rate base at a pace in excess of the amount that's being depreciated? Is that correct?

A. That is correct. And for most utilities and PacifiCorp in particular that's the case.

Q. In going forward, Mr. Mullins, do you anticipate -- based on what we know about PacifiCorp's future investment plans in transmission and generation, would you expect for the foreseeable future PacifiCorp's rate base to continue to grow year over year?

A. I would.

Q. All right. So let's look at this next paragraph here where the FERC is explaining this. It says, "Continual tax deferrals are often referred to by the misnomer 'permanent tax savings.' This term has the connotation that taxes are not only deferred but are also somehow permanently forgiven. This is inaccurate. Regardless of the number of individual timing differences affecting a given utility, each such timing difference will reverse so that, over the life of the transaction, the total amount of the transaction recognized for ratemaking will equal the total amount recognized for tax purposes. Deferred taxes associated with each timing difference are, in fact, recognized when revenues associated with the transaction are recovered, whether or not the reversals of an initial timing difference are replaced by new timing differences of the same or larger magnitude." Do you see that?

A. I do.

Q. Was it your intention in your testimony to claim that the taxes that you're analyzing were permanently forgiven or otherwise never paid?

A. Absolutely not. So, yeah, if I had given that impression, that was not my intention. So over time, under either method, all of the taxes paid by customers will be paid by the utility. It's just a matter of when those taxes get paid by the customers and whether they are loaning money to the Company.

Q. Okay. Mr. Lowney also asked you a series of questions in the discussion about the DA/RT adjustment that asked you to talk about the settlement in the recent Oregon TAM or T-A-M case that you were involved in. Do you recall that series of questions?

A. I do.

Q. Okay. One of the things that I don't know was made clear through that questions was, as I understood your testimony, there was an adjustment proposed -- or excuse me, an adjustment that was part of that settlement of $18 million total-Company to the baseline net power cost; is that correct?

A. Correct.

Q. Okay. And can you please describe whether that $18 million was calculated by the stipulation accepting a specific collection of adjustments or was calculated in what has been called sometimes a black box approach where there was a number that was agreed to without accepting or rejecting any specific adjustment?

A. So that's correct. So it was a black box adjustment, and it didn't address any specific issues, and so when the Oregon Commission approved that settlement, they didn't discuss or evaluate the merits of any particular issue in the case.

Q. So in that settlement, although your client was not a party to that settlement, is it fair to say that that settlement captured at least some of the value of the adjustments that you recommended in Oregon without specifically accepting or rejecting any of them in particular?

A. Yeah, so in Oregon, the Oregon staff, they proposed several of the same adjustments that I had proposed, including rejecting the DA/RT method change and market caps adjustment. So when they accepted that black box, it was presumably in consideration of some of those same adjustments.

Q. Okay. In the questioning from Chairman Throne, do you recall a discussion about sort of the origin and history of the Aurora model?

A. Yes.

Q. In that discussion, at one point you used the word "WECC" or "WECC-wide." Do you recall that?

A. Yes.

Q. Can you define just for the record what WECC is?

A. It's the Western Electricity Coordinating Council. So that's the interconnected region in the western United States for all of the balancing areas in that area.

MR. NELSON: Thank you very much.

I have no further questions of this witness.

MR. WILLIAMS: Mr. Mullins, you're excused.

THE WITNESS: Thank you.

MR. WILLIAMS: Would WIEC like to call its next witness?

MR. NELSON: We would. And Miss King will do so.

MS. KING: Thank you. WIEC calls Mr. David Garrett.

MR. WILLIAMS: Good afternoon, Mr. Garrett.

THE WITNESS: Good afternoon.

MR. WILLIAMS: Would you raise your right hand, please.