- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

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Rocky Mountain Power's) DOCKET NO. 24-035-01
Application for Approval of)
the 2024 Energy Balancing)
Account)
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** REDACTED **

PUBLIC HEARING TRANSCRIPT

Wednesday, January 22, 2025

At 9:02 a.m. MT

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160 East 300 South
Room 403
Salt Lake City, Utah 84111

Reported by: Brooke Simms, RPR, CCR, CSR

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INDEX (Cont'd)

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Confidential Portions Redacted: Pages 41 to 67, 196 to 223

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PREFILED TESTIMONY ADMITTED INTO EVIDENCE

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EXHIBITS ADMITTED INTO EVIDENCE

EXHIBIT	DESCRIPTION	PAGE
DPU Cross Exhibit 1	15 United States Code Annotated 391	78
OCS Exhibit 1.1 D	Philip Hayet's Resume	226

P R O C E E D I N G S

CHAIR FENN: Okay. Good morning. Let's go on the record. It's a little bit like deja vu to see everybody here again. We're going to have a hearing today on the Rocky Mountain Power's application for approval of the 2023 energy balancing account Docket Number 24-035-01, and we'll take appearances of counsel.

Let's start with Mr. Kumar.

MR. KUMAR: Thank you, Chairman. On behalf of the company Rocky Mountain Power. My name is Ajay Kumar. Appearing with me is Ms. Katherine Smith and Mr. Matt Moscon of the firm Mayer Brown.

CHAIR FENN: Okay. Thank you very much. Let's go to the Division.

MR. GRECU: I just have a quick question. Do you want us to introduce our witnesses as well?

CHAIR FENN: I think we know who they all are. We're going to do this like a regular proceeding, and you don't need to do that right now.

MR. GRECU: Okay. Thank you.

Patrick Grecu and Patricia Schmid as assistant attorneys general representing the Division of Public Utilities.

CHAIR FENN: Okay. Go ahead.

MR. MOORE: Robert Moore, assistant attorney general, representing the Office of Consumer Services.

CHAIR FENN: Okay.

MR. RUSSELL: Phillip Russell representing Utah Association of Energy Users.

CHAIR FENN: Okay. Now, do we have any lawyers for parties that are on virtually? Okay. Just witnesses.

One of the -- the first item we need to do preliminarily is approve the motion to have one of the witnesses appear virtually. I think we already approved one for Rocky Mountain Power's. We issued an order on that, but, Ms. Schmid, would you address that?

MS. SCHMID: The order for Rocky Mountain Power also permitted the Division's witness to participate remotely, and that's Mr. Philip DiDomenico. I believe that the Office recently filed a motion requesting permission for its witness to appear remotely because he is trapped back east due to a snowstorm.

CHAIR FENN: That was Mr. Moore. I saw you shaking your head. I thought you wanted to be acknowledged. So I acknowledged you first.

MR. MOORE: Yes. Ms. Schmid is correct. Our witness was at the airport when his flight was canceled, and there was a whiteout in Atlanta, and he was unable to travel to Utah. So we filed an emergency motion for him to testify virtually, and he's on the line now.

CHAIR FENN: And the name of that witness is?

MR. MOORE: Phil Hayet.

CHAIR FENN: Mr. Hayet. Okay. All right. I don't think we have any objection to that. So we're going to grant the motion. What are we going to do at this point? So that motion is granted, and we appreciate Mr. Hayet trying to make the effort to get here.

Pretty unprecedented storm if you looked at the weather patterns of everything along the Gulf Coast having several inches of snow. So we can understand why he would not be able to travel here.

All right. Are there any other preliminary matters we want to discuss before we proceed with calling witnesses? Anything?

Okay. Let's turn to Rocky Mountain Power and call your first witness.

MS. SMITH: Yes. The Company would like to call Jack Painter as its first witness.

CHAIR FENN: Okay. Mr. Painter, if you'll come forward. Welcome, Mr. Painter.

THE WITNESS: Good morning.

CHAIR FENN: If you'll raise your right arm.

JACK PAINTER

was called as a witness, and having been first duly
sworn to tell the truth, testified as follows:

CHAIR FENN: Thank you. You may be seated.

Ms. Smith?

MS. SMITH: Yes.

DIRECT EXAMINATION

BY MS. SMITH:

Q. Mr. Painter, can you state and spell your name for the record.

A. Yes. My name is Jack Painter, J-a-c-k P-a-i-n-t-e-r.

Q. And what is your role with the Company?

A. I'm a net power cost advisor.

Q. Did you cause to be filed direct, rebuttal, and surrebuttal testimony in this proceeding?

A. I have.

Q. Do you have any changes or corrections you'd like to make?

A. I do not.

Q. And if I asked you the same questions stated in your testimony, would you provide the same answers?

A. I would.

MS. SMITH: Okay. At this time the Company would like to move for admission of Mr. Painter's testimony and correlating exhibits.

CHAIR FENN: All right. Seeing no objections to that, we will accept the testimony and the corresponding exhibits into the record.

(Jack Painter's prefiled testimony and exhibits were admitted into evidence.)

Q. (BY MS. SMITH) Mr. Painter, did you prepare a summary today?

A. I have.

Q. Please proceed.

A. Good morning, Chair Fenn, Commissioner Clark, and Commissioner Harvey. My name is Jack Painter, and I'm a net power cost advisor for Rocky Mountain Power.

The Company filed its annual EBA application on May 1st, 2024, for the deferral period of January 2023 through December 2023. The Company requested recovery of $455 million, which consisted of 450.9 million for the deferral excess EBA costs calculated as the difference between actual cost and base rates for net power cost, wheeling revenue, and production tax credits; a $41.5 million credit for sales made to a special contract customer; and 45.5 million in other costs, credits, and interest which included interest accrued through the rate effective period.

At the interim rates hearing, the Commission declined to approve the inclusion of interest through the rate effective period in the Company's application and instead have the Company include carrying charges that accrue during the collection period in the next EBA filing. With this change, the Company decreases interim rate EBA recovery by $24.2 million.

The DPU, OCS, and UAE filed testimony in this proceeding with various recommendations. Through the various rounds of testimony, parties have revised and withdrawn some of the recommendations. At this point the remaining proposed adjustments in this case that are in front of the Commission today are an adjustment of 0.6 million, including interest for replacement power cost associated with outages at the Company's thermal generating plants -- the Company's response to this adjustment will be addressed by Company witness Mr. Richards; an adjustment of 19.4 million, including interest for Washington CCA cost, which will be addressed by Company witness Mr. Wilding; an adjustment of 72.3 million, including interest for trading activities on the west side of the Company system, which will also be addressed by Company witness Mr. Wilding; and, finally, an adjustment of 4.8 million for prior period Schedule 137 costs that I will address.

My testimony demonstrates and supports the inclusion of prior period Schedule 137 costs in this EBA filing. Prior period costs are permissible under Utah Code through the EBA. I have provided multiple examples of prior period adjustments, including current and prior EBA filings. Most importantly, in my surrebuttal testimony, I provided an example of prior period costs that were not previous included in an EBA filing due to an error which was acknowledged by the DPU and ultimately approved by the Commission.

On behalf of Rocky Mountain Power, I respectfully request the Commission approve the EBA as adjusted through the interim rates hearing and issue an order approving the Company's requested recovery of 431.6 million in EBA costs, making the interim rates on Schedule 94 final.

Thank you.

CHAIR FENN: Thank you, Mr. Painter.

We'll -- do you have any other questions you want to ask for clarification, Ms. Smith?

MS. SMITH: No. Mr. Painter is available for cross-examination and questions.

CHAIR FENN: Okay. Let's go to the Division.

MR. GRECU: I just have a few questions.

CHAIR FENN: Sure.

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CROSS-EXAMINATION

BY MR. GRECU:

Q. Mr. Painter, in your response testimony, you stated that the Commission has allowed --

(Reporter clarification.)

Q. -- the Commission has allowed prior period adjustments and that prior period adjustments are common in the EBA; is that correct?

A. That is correct.

Q. And you list some examples too, like liquidated damages payments resulting from a wind energy provider who did not meet contract obligations in the EBA true-up of the variance between actual customer collections and the approved EBA for the deferral year from two years prior due to the interim rate structure; is that correct?

A. That is correct.

Q. In these examples, are these prior period adjustments to rectify accounting errors made by the Company?

A. In those examples, no, those are not.

MR. GRECU: Okay. That's all my questions. Thank you.

CHAIR FENN: Okay. Mr. Moore?

MR. MOORE: No questions. Thank you.

CHAIR FENN: Okay. Mr. Russell, do you have any questions?

MR. RUSSELL: No questions. Thank you.

CHAIR FENN: Okay. All right. Thank you.

Let's go to Commissioner Harvey.

EXAMINATION

BY COMMISSIONER HARVEY:

Q. Hello and welcome.

A. Good morning.

Q. Just to follow up on the DPU's question, the implicitness there is that the reason this adjustment is being proposed by the Company -- or not adjustment, but this amount to be included is simply because it was an error on the Company's part rather than an exogenous factor; is that correct?

A. Yes. To the DPU's questions about the examples I provided, in those specific examples, those were not related to Company error but more due to timing. In -- in the final example I provided in my surrebuttal testimony, that provides another example of a prior rate adjustment that was due to an error.

Q. Okay. And that -- of the adjustments that are at issue in the case that you listed, that's -- this adjustment related to Schedule 137 is the only one that your testimony directly addresses. You mentioned

Company witnesses would cover the others?

A. My -- my testimony only covers the Schedule 137 adjustment.

Q. Okay.

A. But all of the different examples I provided through my various rounds of testimony I'm prepared to discuss.

Q. Oh, I'm sorry. I don't think I was clear on my question. On the other adjustments --

A. Yes.

Q. -- that are being proposed --

A. Right. Yes.

(Cross-talk. Reporter interrupts.)

COMMISSIONER HARVEY: Sorry. I should have been more clear. That's all I have. Thank you.

CHAIR FENN: Commissioner Clark.

EXAMINATION

BY COMMISSIONER CLARK:

Q. You addressed carrying cost in your summary, and I wonder if you could just go a layer deeper with respect to those. My recollection is that initially the Company proposed recovering the EBA balance for 2023 over a two-year period and that the Commission's order for the balance to be recovered over a one-year period affected that -- that carrying cost calculation obviously, but could you describe again how it was affected or to what degree? And what I'm particularly looking for is whether or not the amount that you've described as -- for proposed recovery today includes any carrying charges for the balance of the account.

A. Right. So there's a couple of kind of nuances there that I'll explain. When the Company filed its original application, we did propose a 24-month amortization period as an option to help reduce, you know, rate impact. And if I remember accurately, through testimony, other parties suggested or -- to keep the original 12 months. By going from 12 months to 24 months, you would increase the amount of carrying charges during that time frame.

When -- but the second part of that is, is that when the Company files application, due to the size of the balance, in order to reflect more accurate rates, we calculated what we estimated the carrying charges to be throughout the collection period and included those upfront with the idea being if we didn't do that and we got to the end of the time frame, there could be a large balance to put into the next EBA.

So those were kind of the two issues at hand. And so at the interim rates hearing, ultimately it was -- the Commission decided to remain with the original 12-month amortization and also remove the carrying charges as far as from the collection period to the end. There are carrying charges in this application that are for the deferral period, beginning January 1st, 2023, up until interim rates begin.

So the issue at hand that I mentioned was for the time frame of once rates began amortizing and collecting from customers.

Q. So my understanding of what you've just told me is that there is, in the amount proposed for recovery, the appropriate carrying charge through the -- you're saying through the interim rates order, the date of the interim rates order. Is that -- is that correct?

A. Right.

Q. Beginning with January 1, 2023?

A. Yep. So you're right. The carrying charges included in this application include January 1st, 2023, right until interim rates began.

Q. Thank you.

A. You're welcome.

EXAMINATION

BY CHAIR FENN:

Q. So, Mr. Painter, in your summary, you said that, with respect to this prior case where the Commission allowed -- an exception allowed costs to be recovered, you said that was due to an error. Would you explain that a little more --

A. Yeah.

Q. -- thoroughly to me?

A. Definitely. So in that -- in that docket where we filed for prior period cost, there was an error discovered in the Company's metering system that had to do with the calculation of loads between Idaho and Utah. Because of the metering error, it altered the allocation factors for cost allocation for net power cost, and it shifted excess cost to Idaho customers and under-recovered costs to Utah customers.

And so we updated our calculations for that prior -- or for that current EBA filing and the prior period and sought recovery of those costs from Utah customers due to that error. So it included that current EBA at the time and also the prior deferral period.

Q. So how do you think that's analogous to the circumstances here?

A. I think it's very analogous to that because in this case, for the Schedule 137 cost, there was an error that moved -- there was an error that caused those -- Schedule 137 cost to not move from the Company's billing system over to its net power cost accounting system.

When the error was discovered, we made the prior period entry to recover those costs. Customers received the benefit of that generation that came onto the system, and the Company is just seeking now to just recover those costs for those prior periods.

Q. So do you agree that the general principle is that since you are required to make an annual EBA filing that expenses should be -- recovery of those expenses should be close in time to when there's cost -- the cost originated?

A. Yes, I do agree with that, but also understand that the EBA is a balancing account, and not all transactions can be closed as -- as close as possible and -- which I think is the intent of the prior period order that allows the recovery of costs for -- for prior deferral periods.

Q. I guess I'm still trying to understand from the testimony why it is you could not have included that approximately $4.8 million from Schedule 137 costs that were accrued between January 2020 and December of 2022 in the prior EBA?

A. Good question, and they could have and should have. It is definitely a Company error that those costs were not recorded between the billing system and our net power cost accounting system. So I -- I agree that could have and should have but --

Q. The costs weren't in dispute. It wasn't unknown. The costs were known and knowable; correct?

A. Exactly, yes.

Q. Okay. So hasn't the -- you would have a better way to respond to this question that is outside the scope of my experience -- but haven't costs in the past been allowed as an exception to the -- to the practice of being included in that given year's EBA -- haven't those been primarily situations where the costs were unknown or unknowable at the time of the filing?

A. I think in common examples of prior period adjustments that is the case, but not -- not always. I believe the final example that the Company demonstrated is an example of an error that occurred and that while could have been knowable wasn't knowable to the Company at the time and not discovered until a later period.

Q. Okay. All right. Thank you for your candor. I have no further questions.

CHAIR FENN: I should have gone back to Ms. Smith to see if she had any redirect after the cross or --

MS. SMITH: It's okay. I did not have any redirect after the cross.

CHAIR FENN: Okay. All right. All right. I think that's everybody. Mr. Painter, thank you very much for appearing today and testifying. I appreciate it. It was very helpful.

THE WITNESS: Thank you.

CHAIR FENN: You can be excused.

The Company want to call its next witness?

MR. KUMAR: Thank you, Chairman. We'd like to call Mr. Robert Meredith who is appearing, I believe, electronically.

CHAIR FENN: All right. Mr. Meredith?

THE WITNESS: Can you hear and see me?

CHAIR FENN: Yes. We can see you. I understand the way we've set it up today is you cannot see us; is that correct?

THE WITNESS: That is correct. I can hear you just fine.

CHAIR FENN: Okay. We -- the reason we did that is we had some problems with the technology last time around. We've decided this will be a much more efficient way to handle the hearing. You will not have a visual access to the hearing room, but we can see you. So appreciate you being with us today, Mr. Meredith.

Will you raise -- please raise your right arm.

ROBERT MEREDITH

was called as a witness, and having been first duly

sworn to tell the truth, testified as follows:

CHAIR FENN: Thank you, Mr. Meredith.

Okay. We'll go to Mr. Kumar.

MR. KUMAR: Yes.

DIRECT EXAMINATION

BY MR. KUMAR:

Q. Mr. Meredith, could you please state and spell your last name for the record.

A. Yes. My name is Robert Meredith, R-o-b-e-r-t. Meredith is spelled M-e-r-e-d-i-t-h.

Q. And how are you employed by the Company?

A. My title with PacifiCorp is the director of pricing and tariff policy.

Q. Have you caused to be filed direct and, I believe, rebuttal testimony and associated exhibits in this proceeding?

A. Yes.

Q. And do you have any changes or corrections to that testimony or exhibits?

A. I do not.

Q. And if I were to ask you the same questions today in that testimony, would you give the same answers?

A. Yes.

MR. KUMAR: Mr. Chairman, I'd like to move for the admission of Mr. Meredith's testimony and exhibits.

CHAIR FENN: All right. Seeing no objection to that, we will admit the direct and rebuttal testimony of Mr. Meredith and the accompanying exhibits. Thank you.

(Robert Meredith's prefiled testimony and exhibits were admitted into evidence.)

Q. (BY MR. KUMAR) Mr. Meredith, have you prepared a summary of your testimony?

A. Yes, I have.

Q. Could you please provide it.

A. Sure. Good morning, Chair Fenn, Commissioner Clark, and Commissioner Harvey. In my direct testimony, I presented the Company's proposed rate spread and prices for the 2024 energy balancing account, or EBA. The proposed rate spread and rate design for the 2024 EBA was prepared in a manner consistent with prior EBA balances. Following the Commission's order approving interim rates, rates increased for customers by $256.5 million or 11.6 percent. This net change is the difference between the prior collection level of $175.0 million and the new collection level of $431.6 million for the 2024 EBA.

In its direct testimony, the Utah Association of Energy Users, or UAE, noted that for rate spread

Schedule 9 was lumped together with Schedule 31 and Schedule 32 but that the actual EBA recovery set for Schedule 31 and Schedule 32 was less than what was assigned to these two schedules. This is primarily because the EBA surcharge for Schedule 32 does not apply to the revenue for purchase power agreement, or PPA, designated for Schedule 32 customers. The shortfall from this difference ends up being assigned to Schedule 9 in the Company's pricing model.

UAE witness Dr. Higgins recommended in his direct testimony that the Commission order the Company to credit Schedule 9 by this amount in the 2024 EBA deferral and fund it on a pro rata basis from all other classes, including Schedule 9. He also recommended that the Commission order the Company to change its methodology going forward in future EBAs so that the deferral costs do not get allocated to revenue associated with the PPA designated for Schedule 32.

In my rebuttal, I largely agreed with Dr. Higgins that the Company's methodology was a simplification that was unfair for Schedule 9. However, the Company recommended a slightly different approach under which Schedule 31 and Schedule 32 would not be grouped together with Schedule 9 for rate spread. Instead, the EBA price applicable to the corresponding full requirement rate schedules would be applied to the billing determinates for Schedule 31 and Schedule 32 to determine their EBA revenue, and the rate spread for all other classes would be dynamically adjusted to account for the EBA revenue from Schedule 31 and Schedule 32.

Making this change would introduce iterative logic to the EBA pricing work papers but would result in a more fair allocation to Schedule 9 and all other customers.

My recommendation for the Commission is to approve this methodology for the Company's EBA filings going forward and to approve adjusting the recovery from Schedule 9 downward by the $3.3 million value shown on my Exhibit RMM-3R and adjusting the recovery from all other full requirement classes to make up the shortfall.

In surrebuttal, UAE agreed with my recommendation. No other parties address this issue. This concludes my summary statements.

CHAIR FENN: Okay. Thank you, Mr. Meredith, for your summary. I appreciate it.

Anything, Mr. Kumar?

MR. KUMAR: No. Mr. Meredith is available for cross-examination and Commissioner questions.

CHAIR FENN: Okay. Let's -- we'll go through the same order. We'll go to the Division first. Do you have any cross?

MR. GRECU: No questions.

CHAIR FENN: Okay. The Office?

MR. MOORE: No questions. Thank you.

CHAIR FENN: Okay. Mr. Russell?

MR. RUSSELL: No questions. Thank you.

CHAIR FENN: Okay. Is Mr. Higgins going to testify later with respect to the position on -- you're in agreement on this essentially?

MR. RUSSELL: He will be testifying later, yes.

CHAIR FENN: Okay. All right. Okay. Let's go to Commissioner Harvey -- let's go to Commissioner Harvey and see if he has any questions.

EXAMINATION

BY COMMISSIONER HARVEY:

Q. Hello.

A. Good morning.

Q. I have just a few questions to clarify my understanding of the EBA procedures as how it relates to Schedule 31 and 32. So these questions are not directly concerning the proposed issue. I just want to understand it a bit better.

So the PPA -- energy derived from PPAs -- is that not subject to any EBA charges because it's directly contracted by those customers, or what's the -- what's the mechanism or logic there?

A. Sure. So what happens with the EBA is that it's applied to power and energy charges, not to any other charges, not to customer charges, not to facility charges. The PPA is really a unique type of revenue for Schedule 32 customers where the Company is paying that PPA, but it is essentially like a pass-through in the sense that the -- the customer pays the Company. The Company turns right around and pays the PPA. And so it is -- the EBA percentage is not applied to that PPA price. Rather, for Schedule 32 customers, the EBA surcharge gets applied to -- really to supplemental power and energy charges, which are reflective of the service they're receiving from the Company.

Q. And the -- the cash flows that are associated with those PPAs in terms of what the Schedule 31 and 32 companies paying RMP and then RMP pays the supplier -- do those cash flows go through the EBA, or are they accounted for separately?

A. Oh, boy. I am not sure whether those are specifically in the net power costs that are in the EBA or not. I know that I looked at this in detail when I was preparing the general rate case to try to make sure that we understood exactly where it was in or out. I would probably have to look at my records a little bit deeper to remember whether it was actually in the EBA or not. I don't remember right now.

Q. Okay. Thank you. As a follow-up to that, is it your understanding that the Schedule 31 and 32 customers pay all of the costs associated with getting that power?

A. I do believe that Schedule 31 and Schedule 32 pay all the costs of the PPA, the PPA being specific to 32, not to Schedule 31. It's not a concept for Schedule 31, but the PPA for Schedule 32 customers is entirely paid for by those customers.

Q. All right. So based on those answers, I would conclude -- and tell me whether I'm correct or not -- that whether those are included in the EBA or not, the net effect should be zero on the EBA?

A. I would think -- I think that the net impact is zero for other customers since it is a pass-through. Trying to think here mechanically how that would work with the EBA -- I think that -- yeah. I don't want to guess what it is, if it's in or out, but I would think that that would be balanced with the revenue that comes in because it's revenue that the Company receives then an expense that the Company pays out, but I don't want to guess if it's in there or not specifically in the

EBA, but, yes, I -- my understanding is that it is entirely paid for by those customers.

Q. Thank you. And then a final question. You just mentioned -- and I should have been aware of it -- but that the 31 -- Schedule 31 is not associated with PPAs. So why were they part of this discussion in terms of -- it's always referred to Schedule 31 and 32 and then Schedule 9. What was the connection with Schedule 31? Is it just the modeling?

A. It is the modeling. I think that Dr. Higgins identified the PPA as the largest source of -- of difference for Schedule 9. I think upon -- reflecting upon what Dr. Higgins was saying, I came to a slightly different conclusion, which was that Schedule 9 is grouped together with Schedule 31 and 32, and then the ultimate rate spread for that sort of class of those three schedules is then lumped together. I think that the trouble with the way the modeling was working, from my perspective when I dive into it more, is that the rate spread was just kind of a uniform percentage applied to 9, Schedule 31, Schedule 32, including Schedule 32's PPA, which is not insignificant because there's a large PPA component to it.

But in reality, both of those classes -- sorry both of those rate schedules, Schedule 31 and Schedule

32, have a part of their service that is supplemental service that is like a full requirements customer with power charges and energy charges, but a significant part of their revenue is backup facilities charges and the PPA costs for Schedule 32. That backup facilities charge is there to account for the fact that a partial requirements customer has on-site generation and depends upon the company's grid to serve it really at a moment's notice if their generation becomes unavailable.

And so because of that, even though those rate schedules are relatively smaller than Schedule 9, it's sort of overinflated the amount of costs being assigned to that bundle of rate schedules -- Schedule 9, Schedule 31 and Schedule 32. And then once it went into the rate spread itself, that total pot of dollars assigned to those three rate schedules -- it played out to where the percentages were applied to the power and energy charges, but then more costs got assigned to Schedule 9.

And so the Company's recommendation there is to instead pull out Schedule 31 and Schedule 32, treat them independently, meaning that, in an iterative fashion, the power charges and energy charges would be applied to the percentage for full requirements customers for the EBA price. That revenue would be determined and then would feed back into the amounts that are assigned to all rate schedules, which I think is a better logic for this to keep Schedule 9 just isolated on its own since that is ultimately what the allocator is looking at -- is the cost of service for Schedule 9.

Q. Thank you. Thank you for that explanation. That's all my questions.

CHAIR FENN: Commissioner Clark?

COMMISSIONER CLARK: I don't have any questions. Thank you, Mr. Meredith.

EXAMINATION

BY CHAIR FENN:

Q. Mr. Meredith, I just wanted to understand the dollars amounts. So as I read your rebuttal testimony, you recommended that Schedule 9 receive a $3.3 million lower price increase; is that -- is that accurate?

A. Yes.

Q. There was also a statement that Schedule 31 and 32 would experience a -- and I think this is your language -- a slightly lower price increase.

A. Right.

Q. What is that slightly lower price increase? I didn't see that.

A. Yeah. Let me pull that up here. It would be on my Exhibit RMM-3R. And if I'm looking at that and I look at Schedule 31 and Schedule 32, for Schedule 31 it would be $114,000. For Schedule 32, it would be $18,000.

Q. Okay. All right. Okay. I understand why you would have referred to it in your testimony just as a slightly lower price increase, but thank you for those numbers, but the bottom line is, is that if you add those numbers together, the 3.3 million and then these relatively minor amounts for Schedule 31 and 32, the total of that is then proposed to be passed on, if you will, or the impact of that would be to increase the other schedules, and that is estimated by you to be a .2 percent price increase; is that correct?

A. That is correct.

CHAIR FENN: Okay. All right. I have no further questions. Thank you, Mr. Meredith.

Anything else from Mr. Meredith?

Okay. We'll excuse you. Thank you for testifying today, Mr. Meredith, and you can -- you can drop off if you choose, or you can stay on and participate electronically if you'd like. Okay? Thank you.

THE WITNESS: Okay. Thank you.

CHAIR FENN: Appreciate it, Mr. Meredith.

Okay. We'll turn back to the Company.

MS. SMITH: Yes. The Company would now like to call Brad Richards as its next witness.

CHAIR FENN: Mr. Richards, welcome. Thank you. Would you please raise your right arm.

BRAD RICHARDS

was called as a witness, and having been first duly sworn to tell the truth, testified as follows:

CHAIR FENN: Thank you very much. You may be seated.

DIRECT EXAMINATION

BY MS. SMITH:

Q. Mr. Richards, can you state and spell your name for the record.

A. Yes. It is Brad Richards, B-r-a-d R-i-c-h-a-r-d-s.

Q. And what is your role with the Company?

A. I am the vice president of thermal generation.

Q. Did you cause to be filed rebuttal -- sorry -- response, rebuttal, and surrebuttal testimony in this proceeding?

A. Response and surrebuttal.

Q. Thank you.

A. Yes.

Q. Do you have any changes or corrections to those testimonies?

A. I do not.

Q. If I asked you the same questions in those testimonies, would you provide the same answers?

A. Yes.

MS. SMITH: At this time I'd like to move for admission for Mr. Richards' testimonies and correlating exhibits.

CHAIR FENN: Okay. Were there exhibits to both the response and the surrebuttal testimony?

THE WITNESS: I don't believe there were.

CHAIR FENN: Yeah. I didn't remember seeing exhibits.

MS. SMITH: My apologies. I was getting going with my notes. I'll take that back.

CHAIR FENN: No problem. It's just testimony. There's no exhibits; correct?

THE WITNESS: Correct.

CHAIR FENN: Okay. That's what I thought. Okay. All right.

MS. SMITH: Thank you for that correction. Sorry.

CHAIR FENN: No -- no problem. I just wanted to make sure I wasn't losing my mind because I didn't see any testimony -- or any exhibits when I was reviewing the testimony.

Okay. Any objection? Seeing no objections, we'll admit Mr. Richards' response and surrebuttal testimony. Thank you. All right.

(Brad Richards' prefiled testimony was admitted into evidence.)

MS. SMITH: Thank you.

Q. (BY MS. SMITH) Mr. Richards, have you prepared a summary today?

A. I have.

Q. Please proceed.

A. Good morning, Chair Fenn, Commissioner Clark, and Commissioner Harvey. As part of this docket, my team and I provided portions of the initial filing requirements, including the thermal outage log and performance statistics. We further provided useful information to support the regulatory review process by submitting over 90 additional documents and responses to over 30 supplemental questions comprising six sets of data requests.

In my response and surrebuttal testimonies, I respond to the Daymark audit report and their recommendations for disallowance related to outages at the Company's thermal generating units. I also correct certain errors made by Daymark related to those outages.

My testimony demonstrates how the Company diligently seeks additional resources when required and implements unique solutions to properly address and resolve issues as elaborated in the descriptions I provided related to the boiler tube --

(Reporter clarification.)

A. -- related to the boiler tube leak at Naughton Unit 2. As I've explained, a chemical cleaning alone would not have resolved the issue in itself and is itself not an insignificant undertaking.

Resolution first required new equipment and an enhanced approach to water chemistry analysis as well as a unique method to locate the source of the contamination before repairs were made. The Company followed sound engineering practices to identify and address the issue through an iterative process before then completing repairs and performing a thorough cleaning of the boiler.

The Company's generating units are complex facilities which utilize diverse array of equipment to provide dispatchable energy to its customers. My testimony demonstrates the Company makes decisions regarding the maintenance repair and replacement of equipment based on observable, operational information and in consideration of safety while making reasonable efforts to utilize remaining useful life of its equipment.

Daymark improperly conflates imprudence with avoidability and the issue is whether an outage has occurred in the course of a prudent operation, not whether an outage was potentially avoidable. My testimony demonstrates that the Company prudently manages its thermal fleet to the benefit of its customers. I recommend the Commission reject the proposed disallowances for the four remaining thermal outages referenced in the Daymark audit report. And that concludes my summary.

MS. SMITH: Thank you.

At this time, considering the content likely to be discussed, the Company would like to suggest moving into a confidential session.

CHAIR FENN: Okay. Does anybody want to address that -- have any objection to that?

Okay. So we will -- we are now hereby convening a confidential session of this proceeding. This will be closed to anyone who has not signed the confidentiality agreement. So if you're present -- if there's anyone present in person who is not a signatory who hasn't signed the document and submitted it to the Commission on the record as bound by the confidentiality terms, we'll ask you to leave.

And I'll ask the, you know --

MS. PASCHAL: There's a phone number I don't recognize.

CHAIR FENN: Okay. We'll cover that one too. So is there anyone here who needs to step out for this session? You've all signed -- and I guess I'll ask the counsel. You can look around and make sure that there's nobody here you don't recognize that you've got any concerns about. The only other ones are Commission staff that are in here.

There is also a phone number. So everyone who's on the -- on the feed, the video feed -- I know Mr. Meredith, Mr. DiDomenico, and Mr. Hayet -- I'm sure you signed the -- the confidentiality agreement. There's a telephone number there that I don't recognize, and if you could identify yourself. It begins 801 --

MS. PASCHAL: That's us.

CHAIR FENN: I did -- I did this last time, didn't I? You're going to learn by your own experiences, but apparently it's going to take me a little more than twice to figure that out.

Okay. So we also have a 770 that ends in 15. Can you identify yourself?

MR. HAYET: Yes. Can you hear me? This is Philip Hayet.

CHAIR FENN: Okay. That's interesting. You're up there twice.

MR. HAYET: I'm up there twice because I couldn't hear. So I -- I called in, and now I'm able to hear. I don't know why.

CHAIR FENN: Okay. Great. We've resolved that. We just didn't recognize the number. That's fine. All right. So anybody need to leave? Okay. We're -- anybody who's not signed the confidentiality agreement is out of the room. This portion of the proceeding -- what do we do with that, Melissa? It's not -- it's obviously --

MS. PASCHAL: It's not being streamed anymore.

CHAIR FENN: It's not being streamed any longer. You quit streaming. Okay. So it's not being streamed. So we should be -- we should be good. I think we can go forward now.

* * * * *

(THE FOLLOWING PORTION OF TRANSCRIPT PAGES 41-67 HAVE BEEN MARKED CONFIDENTIAL.)

CHAIR FENN: We're ready to move on to the next witness.

MR. KUMAR: Thank you. We are going to call Mr. Wilding next.

CHAIR FENN: Okay.

MR. KUMAR: But Mr. Wilding's summary, I believe, is entirely public, but to the extent that there are questions on, you know, hedging practices and things like that, we may get into confidential session. So I just want to note that for the record.

CHAIR FENN: Let's deal with it as it comes up. If it comes up and he responds, "That would require me to provide confidential information," we'll go back into close session. Okay? Let's go ahead then.

MR. KUMAR: Thank you. The Company would like to call Mr. Wilding then.

CHAIR FENN: Mr. Wilding, I would say welcome back, but I'm sure that's not appropriate. You don't -- you don't feel welcome in any of these proceedings. No one ever does.

All right. Will you raise your right arm to the square. Thank you.

MICHAEL G. WILDING

was called as a witness, and having been first duly sworn to tell the truth, testified as follows:

CHAIR FENN: Thank you. Please be seated.
MR. KUMAR: Mr. Wilding, are you ready?
THE WITNESS: I am.

DIRECT EXAMINATION

BY MR. KUMAR:
Q. Could you please state and spell your name for the record.
A. Yes. It is Michael G. Wilding. That's M-i-c-h-a-e-l, middle initial G, W-i-l-d-i-n-g.
Q. And how are you employed by the Company?
A. I am the vice president of Energy Supply Management.
Q. And have you caused to be filed response, rebuttal, and surrebuttal testimony with associated exhibits?
A. Yes.
Q. And do you have any changes or corrections to that testimony?
A. No, I do not.
Q. And if I were to ask you those same questions today, would you give the same answers?
A. Yes, I would.
MR. KUMAR: I'd like to move for the admission of Mr. Wilding's testimony and exhibits.
CHAIR FENN: Okay. Without objection, we'll

admit the response and rebuttal and surrebuttal testimony of Mr. Wilding with the accompanying exhibits.

(Michael Wilding's prefiled testimony and exhibits were admitted into evidence.)

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

A. Yes, I have.

Q. Could you please provide it?

A. Yes, I will. Good morning, Commissioners. Thanks for having me again.

In my testimony I explain how Utah customers benefit from PacifiCorp's system. PacifiCorp operates two balancing authority areas with transmission connecting the two areas. The first balancing authority area is PacifiCorp West, or PAC West, which generally consists of our generation and transmission assets and customer loads geographically located in California, Oregon, and Washington. From PacifiCorp West, we can access the power market hubs in the northwest -- namely the Mid-C, or Mid-Columbia, market and the California-Oregon Border, or COB, market hubs.

Our PacifiCorp East balancing area for -- our balancing authority area, or PACE, generally consists of our generation and transmission assets and our customer loads geographically located in Idaho, Utah, and

Wyoming. From PACE, we are able to access the southwest power market hubs: Palo Verde, Mona, and Four Corners. And the Company co-optimizes the two balancing authority areas and uses its transmission rights to serve load in a least cost manner.

A big part of providing reliable energy in a least cost manner is our hedging program, and we hedge by making physical power transactions in the forward market to protect against both price volatility and power supply risk.

My rebuttal testimony first responds to concerns by the Utah Division of Public Utility's witness Mr. Gary Smith who has suggested an adjustment to reduce the allocation of power hedges the Company enters into on the west side of our system from 44 percent to 20 percent. This adjustment is based on the misunderstanding by the Division that Utah customers do not benefit from the load, resource, and geographic diversity provided by PacifiCorp's transmission and generation system.

Specifically, Mr. Smith suggests that all the Company's hedges at Mid-C do not benefit or serve Utah customers. What Mr. Smith does not understand is that the reality is just the opposite of what he has suggested. Utah customers benefit greatly from the

Company having access to and being able to hedge at Mid-C, and the Company uses these purchases of physical energy to serve system load.

Notably, Mr. Smith does not suggest an alternative action that the Company should have taken in place of hedging at Mid-C that would replace the lost energy and still reliably serve load. The obvious alternative is to perhaps instead make those hedges or market purchases in the southwest closer to the Utah load so that purchased electrons would be more likely to be consumed by Utah customers. However, Mid-C is the most liquid market hub in the western United States, and this alternative presents a liquidity problem.

Additionally, Utah customers benefit from the Company hedging at Mid-C because it is generally more cost effective. Most of the Company's hedging activity is in the summer months, and generally speaking the northwest has more mild summers and experiences lower peak loads than the southwest, and the price difference between Mid-C and the southwest typically will reflect that. This is the diversity benefit that I mentioned earlier.

While true that most of the Company's generation is located in PACE, making economic hedges at Mid-C allows the Company to use the flexibility of the

Company's transmission system to benefit all of our customers, including Utah customers. This works by economically hedging at Mid-C, which is the low cost option and the more liquid market, and using that purchase energy to serve load in a PacifiCorp West area and then using the generation geographically located in PACE to serve customers here.

Notably, all customers in each of our states pay for generation across our systems. For example, Utah customers pay the costs of generation located in all of our states, including Oregon and Washington, and Washington and Oregon customers also pay for the costs of generation located in all of our states, including Utah and Wyoming.

If we were to operate the way Mr. Smith seems to be implying, the Company would have to reserve the transmission to send a significant amount of energy from the generation plants located in Utah and Wyoming to PacifiCorp West and then enter into the same amount of hedging transactions in the southwest, likely at a higher cost. It is unclear if the Division understands this concept, because by recommending that the majority of Mid-C hedges be disallowed, they seem to understand that at least a portion of the Mid-C hedges benefit Utah customers.

When Mr. Jones proposed a similar adjustment in the general rate case, it was noted that this new allocation method is inconsistent with the 2020 Protocol, but the DPU believes that is okay as the DPU deems the 2020 Protocol an unjust allocation. However, this is nothing more than cherry-picking the marginal resource used to serve load and disallowing those costs for no other reason than market purchases are the most expensive source.

Presumably, Mr. Smith would rely on the generation resources geographically located in PACE to serve Utah load rather than make hedges or market purchases at Mid-C. The only problem with this, and as I noted earlier, is that customers throughout our six-state service territory have paid for the resources located in PACE and are entitled to the benefits of those resources. Utah cannot simply take all the benefits of those resources.

Additionally, this implication that the 2020 Protocol is unjust is odd as it has been used in multiple regulatory filings and the Division was a signatory.

Finally, the Company has a robust and prudent hedging program to mitigate price volatility and reduce supply risk under increasingly volatile and scarce market conditions. Notably, the Company files a semiannual hedging report with the Commission as is continuously working with the Division and their consultant to improve the program and the documentation available for review in the EBA.

I will additionally address the Company's inclusion of the cost of purchasing allowances for the Chehalis generating facility in order to comply with the Climate Commitment Act of Washington.

Rocky Mountain Power's required to comply with the laws in all of the states in which it operates, and this includes laws related to environmental compliance and taxes. Disallowing recovery of the compliance cost penalizes the Company for complying with Washington's state law. The DPU and UAE do not dispute that the Company is required to obtain emission allowances for Chehalis generation and do not recommend that the Company remove the benefit of Chehalis generation from Utah rates. Instead, they are recommending that the Company remove the generation costs that were prudently -- prudent and necessary for the operation of the facility for the benefit of Utah customers.

I request that the Commission deny the Division's proposal to unreasonably adjust net power costs and that the Commission allow customers to benefit from the load and resource diversity of PacifiCorp's system. Additionally, I recommend the Commission deny the DPU and UAE and OCS's recommendation to remove the CCA compliance cost from the EBA.

Thank you. This concludes my testimony.

CHAIR FENN: Thank you, Mr. Wilding, for your summary. Appreciate it.

Anything before you turn him over for cross?

MR. KUMAR: No. Mr. Wilding is available for cross-examination.

CHAIR FENN: Okay. Let's go to the Division. Ms. Schmid?

MS. SCHMID: Thank you. The Division has just a few questions for Mr. Wilding. Mr. Grecu will pass out a cross-examination exhibit that I'd like to have marked as DPU Cross Exhibit 1, and may he approach the witness when he gives the witness that?

CHAIR FENN: Sure. Absolutely. And he can give it to us first.

MS. SCHMID: Yep.

CHAIR FENN: And then to the witness.

COMMISSIONER CLARK: Thank you.

CHAIR FENN: Okay. We'll give Mr. Wilding a moment or two to review that, but this is -- this would be marked as DPU Cross 1; is that correct?

MS. SCHMID: Yes.

CHAIR FENN: And let's see if anyone has an objection to this exhibit being admitted. Any objection from Rocky Mountain Power? I'll give you a second longer to look it over if you're still looking.

MR. KUMAR: To the extent that this is a section of the United States -- it looks like United States Code, I don't think we have an objection.

CHAIR FENN: As I -- as I look at it -- and let's ask a clarifying question just before we admit it. This is -- there's no commentary on this. This is just an excerpt from United States Code -- USC Code Annotated; is that correct?

MS. SCHMID: That is correct with the statutory references to the public law and things like that.

CHAIR FENN: Sure.

MS. SCHMID: But no commentary.

CHAIR FENN: Yeah. Okay. But this is just something that you pulled off of Section 391 off of Westlaw?

MS. SCHMID: It is.

CHAIR FENN: Okay. Any objections to its admission?

No. Okay. We'll admit DPU Cross 1.

(DPU's Cross Exhibit 1 was admitted into evidence.)

MS. SCHMID: Thank you.

Q. (BY MS. SCHMID) Mr. Wilding, have you had a chance to read this short paragraph?

A. Yes, just -- just now.

Q. I have a -- very few questions. For ease of the record, I'm going to read the paragraph into the record, and I will ask counsel for the Company to help make sure that I read it correctly.

It is 15 USCA Section 391 entitled "Section 391. Tax on or with respect to generation or transmission of electricity." The paragraph reads, "No state, or political subdivision thereof, may impose or assess a tax on or with respect to the generation or transmission of electricity which discriminates against out-of-State manufacturers, producers, wholesalers, retailers, or consumers of that electricity. For purposes of this section a tax is discriminatory if it results, either directly or indirectly, in a greater tax burden on electricity which is generated and transmitted in interstate commerce than on electricity which is generated and transmitted in intrastate commerce."

Did I read that correctly?

A. Yes.

Q. Thank you.

CHAIR FENN: And we'll just note as a Commission that that -- that's an accurate -- you read that exactly as it appears in the cross-examination exhibit.

MS. SCHMID: Thank you.

Q. (BY MS. SCHMID) Do I understand correctly that Rocky Mountain Power considers the Washington CCA compliance costs for Chehalis as a tax?

A. I believe that it is analogous -- I can't speak -- it's similar to a tax for sure and functionally works as a tax. It's -- in my testimony I speak to it being a generation cost because the only way to incur that cost and the only way to avoid that cost is either to generate or to not generate at Chehalis. So it is a tax or a price or a cost associated with the emissions at Chehalis due to generating.

Q. Thank you.

PacifiCorp's Washington customers do not pay the same amount for that tax as PacifiCorp's customers in other states; is that correct?

A. Generally speaking, yes. The way -- the way the law works is that Chehalis incurs an allowance for its emissions, and those allowances typically have to be purchased. Now, Washington load -- Washington retail customers receive free allowances from the state of Washington to offset the allowances that are required for their share of the emissions from Chehalis. So generally speaking, yes.

You know, we don't think this is fair. I think I noted that in my testimony. We have a pending lawsuit in the federal court system. The first lawsuit that we brought against the Washington Department of Ecology was dismissed, and we currently have it at the court of appeals. I don't know all the formalities. Sorry. I'm not a lawyer, but, generally speaking, I think that's correct it's at the court of appeals. It's being appealed.

Q. Thank you. Never apologize for not being a lawyer. Some of us have to apologize for. Anyway, I digress.

Okay. Turning now to USCA Section 391 that I just read into the record, I'd like to ask a -- your opinion, as an expert witness for the Company, not as a lawyer, on the layperson's reading of the code.

MR. KUMAR: Mr. Chairman, at this point, I would like to object. I mean, while Ms. Schmid has acknowledged that Mr. Wilding is not a lawyer, I think it's important to state for the record that Mr. Wilding is, of course, still not a lawyer, as we noted a few times now, nor is he a tax expert and that he may not be able to interpret a section of the United States Code regarding taxes that has been placed in front of him.

CHAIR FENN: I think -- thank you, Mr. Kumar. I think that your objections will help us limit the scope of what can be asked of Mr. Wilding, that he's not a tax expert, he's not a lawyer. And if he has an opinion as a layman, as Ms. Schmid has asked, he can answer that, given the parameters or the restrictions on the scope of his expertise.

So you can ask your question again.

MS. SCHMID: Thank you.

Q. (BY MS. SCHMID) Is PacifiCorp's position that the CCA compliance costs are a tax and they affect Washington customers differently than customers in other states? I'm just reiterating what I asked before.

And you can just refer back to your prior answer if that's easier.

A. Okay. I refer back to my prior answer.

Q. Doesn't it seem, from a layman's reading, that the Washington CCA tax would be illegal under 15 USCA Section 391?

A. Again, I'm not a lawyer. So I think, yes, we agree. We do not think the tax is a legal -- I can't -- I know we are making an interstate commerce argument in our case. What section that applies to, I'm not going to opine on that, but, again, as I noted, the Washington CCA has been upheld once already in federal court and then again -- one in a case before ours, again with our first case that was dismissed that we are now appealing.

So it is the current Washington law right now, and, you know, my opinion really doesn't matter. If it's the Washington law and we have to comply with it, and in order to generate at Chehalis we are incurring costs, we think those costs are -- should be, you know, coupled with the benefits, and as the benefits are flowing through to Utah customers, the costs should as well.

So, really, my opinion doesn't really matter. Like, I agree it's an unfair law, and that's partially why we're suing the state of Washington, but as we stand here today, it is the current law, and those costs are being incurred because of generating at Chehalis for the benefit of all of our customers, including Utah customers.

Q. Thank you. I have no further questions.

CHAIR FENN: Okay. Thank you, Ms. Schmid.

Mr. Moore, do you have any questions?

MR. MOORE: I have none. Thank you.

CHAIR FENN: Okay. Thank you.

Mr. Russell, questions of this witness?
MR. RUSSELL: Yeah, I do have some questions.

CROSS-EXAMINATION

BY MR. RUSSELL:
Q. My questions will be limited to your testimony relating to the Climate Commitment Act or the CCA.
Your position in this docket is that the CCA is a -- is a generation tax? Is that your position?
A. It's a generation tax. It's a cost of generation. It's -- again, I'm reading this -- I'm not a lawyer. It's a cost associated with generating at that plant. You incur it when you generate. You avoid it when you don't generate.
Q. Yeah. And I want to touch on that point shortly, but let's -- let's focus on the -- the -- the obligations you have to comply. So there are allowances, I gather, that are required for the Company to acquire them to comply with the law; is that right?
A. Yes, that's right. For every metric ton of greenhouse gas emissions that we incur, we have to buy one allowance to offset that.
Q. Well, but not for every metric ton. You don't have to buy them for every metric ton. You only have to buy them for the metric tons that are associated with serving customers outside the state of Washington;

right?

A. Yes, that's correct. So we receive free allowances for the amount of emissions that are associated with the retail load of Washington customers. That's correct.

Q. Yes. So I actually want to talk about how the no-cost allowances, which I think is the sort of term of art that gets used, are allocated to PacifiCorp. One of the -- the exhibits provided or attached to the rebuttal testimony that the Division provided was a response to a data request that said something to the effect of that no-cost allowances are directly attributable or -- to Washington load but not to Chehalis. Do you recall that?

A. I would need you to point me to the data request and perhaps give me a --

Q. Fair enough.

A. -- give me a copy because I don't have one.

Q. Yeah. And I actually don't have a copy. I'm hoping that the Division can get it to you. It is DPU Exhibit -- and it's to the rebuttal testimony -- 2.4 R.

A. You said 2.4 R? It's a DPU?

Q. Yes. And it is -- it was attached to the rebuttal testimony of the Daymark witnesses, Mr. DiDomenico and Mr. Koehler.

A. Yeah. I -- I'm there. I see it.

Q. Okay. So I was curious about this response -- and this is 11 -- this is the Company's response to DPU Data Request 11.2 B. Where it says, "The no-cost allowances Washington has decided to provide to its own customers is tied directly to Washington's retail load and the attributes associated with PacifiCorp serving that load. The provision of no-cost allowances is distinct from the generally applicable generation tax imposed by the Washington Cap-and-Invest program."

And going back to up to "A," it says, "No-cost allowances are provided based on PacifiCorp's Washington retail load and not specifically for the Chehalis plant."

I read that, and I find myself wondering how is it -- like what is -- how -- how are the no-cost allowances allocated to you? Is it completely irregardless of the amount of generation at Chehalis, or maybe you can just give us a narrative on how the no-cost allowances are allocated?

A. Sure. The Washington allocation no-cost allowances are based on the Washington retail load and then what will be used to serve that load, if that makes sense. So we -- we submit a forecast during a compliance period, which is a -- before the compliance period, which is a four-year period, and we say, "This is the expected Washington load. These are all of the resources that we are going to use to serve Washington load." And not only are -- are the emissions for Chehalis an instate generation subject to the CCA or the carbon -- what is it -- the Climate Commitment Act but so are imports into the -- the -- into the state.

And so you take that, and you look at that, and you say, "Okay, Washington, you're going to have 'X' amount of load, and you're going to be served by this mix of resources, and so you're expected to have this many emissions associated with -- you know, 'Y' amount of emissions associated with the retail load." Part of that is Chehalis, and we receive those no-cost allowances to -- so that retail load in Washington is not -- they receive no-cost allowances for all the -- all the emissions associated with retail load, including the Chehalis emissions.

Q. Okay. I think I understood you to be saying that the compliance obligation for the Washington load includes the Washington allocated generation from Chehalis and then also any out-of-state GHG emitting resources that are allocated to Washington; right?

A. Yeah, yes. That's right. And the nuances of, you know, how those allowances get to PacifiCorp and what we have to retire, not quite up to speed on, but the Chehalis allowances, because we generate in state, we are also required to emit those and -- sorry. So we are the emitting party, and so we have to retire those allowances. So because, you know, it's our load and our generation, we would get the free allowances that we -- are associated with Chehalis, or the no-cost allowances, and then retire those.

Q. Okay. But the -- so we've been talking about no-cost allowances. We're going to spend a little bit of more time on that. I just want to make a distinction here. The allowances that are not the no-cost allowances -- those are applicable only to generation at Chehalis and not to generation outside of the state?

A. That's right.

Q. Okay. In connection with the no-cost allowances, when they are provided to you by the state, is it for an annual period, for a monthly period? Can you --

A. I -- I would need to check, but I believe it's an annual period that -- so we submit the forecast for the four-year compliance period, and I believe those no-cost allowances are deposited into our account annually.

Q. And when do you retire them?

A. It depends -- on when we retire them. We have a holding limit, and so we can only bank and hold so much of the allowances, whether they're purchased or no-cost allowances, and then what we actually do is we move them in -- so we have our holding account, and then we move them into our compliance account. So typically, because we have those holding limits, we do move those no-cost allowances into the compliance account pretty quickly, and then Washington goes into the compliance account and actually retires them.

Q. Is the compliance obligation for all allowances made -- is that done at the same time, or is there a separate compliance obligation timing-wise for the no-cost allowances?

A. No. It's all done at the same time. So you have a four-year compliance period, and then each year you have to retire or put in your compliance account 30 percent of the allowances that you need to comply, and then by the end of the compliance period, end of that four years, you have to retire, essentially, enough allowances for the entire four years. So each year you have a 30 percent target, but by the end of the four years, you have to make up the whole 100 percent.

Q. Okay. And you all have reached out to the -- to the Department of Ecology -- the Washington

Department of Ecology to seek clarification about whether you could apply the no-cost allowances to customers or to emissions that are deemed to match customer load in states other than the state of Washington; right?

A. Yes, we have, and, in fact, during the rulemaking -- you know, the law says that, you know, retail electricity customers would receive free allowances or that we would receive free allowances for the Chehalis generation for the generation associated with those customers. And we did seek clarification, and we also, you know, took the position that, you know, Washington Department of Ecology could interpret that to mean all electric customers, even those outside of Washington. They did not accept our interpretation or our position, and they've said that, no, those no-cost allowances have to be used for Washington.

Q. Right. And so those no-cost allowances are, I guess, articulated as a benefit that are attributable only to Washington customers; right?

A. Yes, that's correct.

Q. Okay. And, in fact, the paragraph that we were reading here in DPU 2.4 R 11(b) makes reference to -- I'll just read the last sentence of the first paragraph. "Therefore, these no-cost allowances are assigned consistent as a state-specific initiative under 3.1.2.1 under the 2020 multistate process interjurisdictional cost allocation methodology, or 2020 Protocol"; right?

A. Right. Those no-cost allowances -- yes. They are allocated to Washington load because that's the Washington law. So to comply with the Washington law.

Q. Okay. Let's talk a bit about the -- the allowances that are not the no-cost allowances. So you mentioned that you have to retire allowances to -- to match -- I forget what the measurement was or the metric was of GHG emissions. You have it off the top of your head; right?

A. Yeah, one million metric ton of emissions is one allowance.

Q. Okay. And so I assume then that -- you've indicated that there's a forecast of generation -- I assumed -- to get the no-cost allowances, I assumed that the Company does something similar when it acquires the allowances that are not the no-cost allowances, or the paid allowances, I guess?

A. So there's two ways that you can acquire allowances or buy allowances. One is just in the bilateral market, so just seeing if anyone has anything for sale. Not a very liquid market. We don't typically do anything there.

The other way that we do it is the quarterly auction, and the way that quarterly auction works is everyone submits a bid, and it's a reverse auction. So they start at the highest bid, and they have a limited amount of allowances that they are selling in that auction, and so you take the highest bid and the number of allowances that that bidder is willing to buy at that price, and then they start working their way down the stack. And when they hit the limit of what they're offering for sale at whatever that price was at that bid, that sets the price for -- for all the -- the allowances. So if you bid above that price, you get allowances at that -- whatever the clearing price was. If you bid below the clearing price, you don't get any allowances.

Q. Okay. And when you are -- and you said these are quarterly auctions?

A. Yes.

Q. When you're acquiring at the quarterly auctions, are you acquiring for -- for emissions that you've yet to emit, or are you acquiring for past emissions, or how do you approach that?

A. I --

MR. KUMAR: I want to -- at this point, I want to maybe slightly object because I think, again, to the extent that Mr. Wilding is disclosing our bidding strategies regarding the purchases of CCA allowances, there are certain restrictions on revealing that information, especially publicly, because they could be -- there's certain market monitoring and market manipulation rules with regards to the market no-cost allowances that exist in Washington.

CHAIR FENN: Okay. So Mr. Kumar has raised a caution here with respect to the potential revelation of confidential information.

Mr. Wilding, can you answer Mr. Russell's question without disclosing confidential information?

THE WITNESS: No. And I don't know if this is appropriate, but I would like to confer with my counsel because the Washington law specifically prohibits us from disclosing our --

CHAIR FENN: We'll take a -- we'll take just a brief recess. We won't leave the bench. We'll just let Mr. Kumar and Mr. Wilding confer for a few minutes. We'll go just off the record for a second.

(Discussion held off record.)

CHAIR FENN: Okay. Let's go back on the record. I guess the first question I have is whether Mr. Russell can rephrase his question so we don't address anything that shouldn't be disclosed pursuant to Washington law.

MR. RUSSELL: I'm wondering if maybe the witness can tell us whether his conference with his counsel has changed his mind about whether he can answer the question as phrased.

CHAIR FENN: Yeah. That'd be fine. Let's ask the question.

A. I can -- I can generally speak to the rules of the auction and compliance obligations, and I can speak to how we account for those and how those costs are reflected in our accounting records, all non-confidentially obviously.

Q. Yeah.

A. What Washington law prohibits disclosure of is our strategy in acquiring those allowances.

Q. Okay. So maybe I can rephrase the question around that. That's helpful.

CHAIR FENN: Okay.

Q. When you go to -- when you go to comply, you've indicated there's some report that, pursuant to if you retire these allowances, do you have to demonstrate that you acquired the allowances before you made the emissions?

A. No. The rules are -- again, it goes back to that 30 percent I was talking about. So you get the four-year compliance period. You have to -- so 2023 -- just using 2023 as an example, it would be part of that four-year compliance period. You have to acquire 30 percent of the allowances in 2023, and they have to be 2023 vintage allowances, and they have to be retired. You can't use prior years to comply with 2023.

So I can't use a 2023 allowance -- vintage allowance to comply with 2024, but if I didn't buy enough or if an emitter -- emitting entity did not buy enough in 2023, they could buy 2024 vintage allowances to cover '23. So you can go backwards, not forwards, and then -- but within the calendar year.

Q. Okay. And you mentioned these auctions occur quarterly; right?

A. That's correct.

Q. Okay. And I assume, based on the way that you described how the auctions work, that the price of a -- of the allowance -- or even average price of allowances that may be acquired at an auction may change from one quarterly auction to the next?

A. That's correct.

Q. Okay. And so when you are running Chehalis and generating electricity there, you don't know at that time what the cost of an allowance might be to satisfy your obligation to retire an allowance for your emissions on any given day; right?

A. That's correct. We don't know what the next market -- or what the next quarterly auction is going to clear at. So we use the best information that we have possible and available, including the past auction clearing prices, including what we're seeing in the bilateral market, and we add a adder to the Chehalis dispatch to account for that the best way -- estimate it the best way we can.

Q. Okay. That's helpful. Is there any other -- you mentioned in your testimony that -- that, you know, you treat -- you know, in your mind, this is a tax or like a tax, and you make specific reference to the Wyoming wind tax. When you pay the Wyoming wind tax, do you know how much that tax is when you generate from the Wyoming wind plants?

A. At one point it was a dollar a megawatt hour. Whether that's increased or not -- but generally speaking I think that's pretty close.

Q. But how does that price change?

A. I'm not a Wyoming tax expert, but I would assume that, based on kind of general knowledge, it would be a -- have to pass a law to change the tax.

Q. Okay. Is there any other generation tax that operates in the way that we just described with the acquisition of allowances for emissions that you're aware of that the Company has to comply with?

A. No.

Q. Is there any other generation tax that the Company is -- it doesn't -- it can't determine the amount of the tax when it is generating?

A. No, not that I'm aware of. And, again, I think whether we interpret it as a tax or not is kind of beside the point. It's a cost associated with generation. It's a generation cost that -- and clearly by the 2020 Protocol, that generation cost should follow the benefits of Chehalis and should be allocated on a system basis.

Q. Well, it's an emissions cost; right? The compliance requirement is for 100 million tons of emissions from that plant, not from the generation of energy; right?

A. Right. But you can't generate without emitting, and so the emissions and generation are hand in hand.

Q. There are other costs that are hand in hand too, though, that aren't taxed, like fuel costs; right? Like, if you don't generate from Chehalis, you also don't -- you don't have to buy gas?

A. Right. And gas is system allocated.
Q. It is, but it's not a tax; right?
A. Right. But it's a generation cost, fuel cost.
Q. But not a tax?
A. Correct.
Q. Okay. And there's a statement in your testimony that I think gets to this point. It's on -- it's in your response testimony at line 444. Let me know when you're there.
A. Yep, I'm there.
Q. Okay. I don't think this starts at the beginning of the line, but it says, "For any energy exported to Utah from the Chehalis plant, there is an incremental dollar per megawatt hour cost based on the GHG allowance price for the test period."
Did I read that right?
A. Yes, you did.
Q. Okay. Help me understand how you get to the dollar per megawatt cost because what we've been talking about is allowances that need to be retired, you know, to match this hundred million tons of emissions, not megawatt hours.
A. Yeah. I typically try not to do math on the fly.
Q. And I don't do it either. I'm with you.

A. But essentially you take the emissions rate of the plant, and you can back into the megawatt hour generation. So the dollars per the allowance and the emissions rate and you can get to the dollar per megawatt hour for that carbon amount.

Q. Yes. So you can forecast a price, and you guys do that for your NPC calculation?

A. Yes.

Q. And you can forecast the energy that you may produce from Chehalis in any given year; right?

A. Right.

Q. And if you know how much of the GHG will be emitted per megawatt hour, you can back into a price per megawatt hour; right?

A. That's correct.

Q. Okay. And so that's where you get this incremental dollar per megawatt hour reference; is that right?

A. That's correct.

Q. But, you know, aren't there other -- I mean, we just talked about fuel costs. Aren't there other -- other things you could, if you wanted to, back into a dollar per megawatt hour increment from the operation of a generation plant?

A. For example?

Q. Labor.

A. You could. And there are some things that we do that. We have variable O&M costs that aren't included in net power costs, but those variable O&M costs are included in the dispatch of some of our -- of our thermal plants because those O&M costs are incurred and are variable with the generation.

Something that is not variable with the generation, though, you could do the math to figure that out. It doesn't necessarily -- it doesn't make sense to do that math and then include it in the dispatch price of that plant because those costs won't vary with -- with the dispatch. But something like variable O&M, something like -- that would include stuff like chemicals or things of that nature that does change with the generation, we do include that in the dispatch price for our thermal plants.

Q. We looked at that response to a data request earlier that made a reference to Section 3.1.2.1 of the 2020 Protocol. Do you recall that?

A. I do.

Q. Your testimony makes reference to a different section of the protocol at 3.1.7. Do you remember that? I could point you to it here if you need.

A. Yes, I do remember that.

Q. Okay. And -- oh, look you have a copy.

MR. RUSSELL: I actually have some copies of the 2020 Protocol I'm going to pass out to the Commission. I've already distributed to counsel. If I may approach?

CHAIR FENN: Please. Okay. So just to make sure, so DPU and OCS already have copies of it? Okay. And do we have a copy for the court reporter? I'll give -- do we have another copy here?

Okay. And you have a copy in front of you, Mr. Wilding?

THE WITNESS: I do.

CHAIR FENN: Okay. All right. Mr. Russell, go forward.

MR. RUSSELL: Thank you.

Q. (BY MR. RUSSELL) Let's go ahead and turn to Section 3, and let's go first to 3.1.7.

A. Okay. I'm there.

Q. It's the section you cited, and this relates to miscellaneous costs and taxes. You indicate in -- on line 485 of your response testimony -- you say that -- sorry. I'll let you get there first.

A. Yeah.

Q. Line 485.

A. I'm there.

Q. Okay. You say here, "Section 3.1.7 of the 2020 Protocol applies to the generally applicable compliance costs associated with purchasing GHG allowances for the Chehalis plant. Section 3.1.7 states that generation-related dispatch costs and generation- and fuel-related taxes are allocated using the System Generation, or SG, allocation factor. Here the Cap-and-Invest program is a generation tax because there is no compliance obligation if there is no generation, and the amount of the compliance obligation is determined by the amount of generation."

Did I read that right?

A. That's right.

Q. Okay. And we've been having a discussion about whether it's a tax. You've indicated today that -- you related to a generation-related dispatch cost, and I'm going to talk a little bit actually about the allocation on the SG factor.

A. Okay.

Q. Can you just give us a brief refresher on what the SG factor is and how it's determined.

A. The SG factor is the system generation allocation factor. It's based on 75 percent of demand and 25 percent on a 12-month coincident peak weighting.

Q. And it is a mechanism pursuant to which a certain percentage of costs that are allocated pursuant to that factor are allocated to the various states; right?

A. That's correct.

Q. Using very round numbers, can you say, using the SG factor, what percentage of costs that are in that SG bucket get allocated to the state of Utah?

A. I think it's roughly 44 percent, 45 percent, around there.

Q. And what about to the state of Washington?

A. About 8 percent.

Q. Okay. And for purposes of the no-cost allowances, you've indicated that 100 percent of those are allocated to Washington customers; right?

A. That's correct.

Q. Okay. And -- but for the paid allowances, the costs of that compliance, the Company has allocated those pursuant to the SG factor; is that right?

A. Yes, that's correct.

Q. Okay. And who pays the 8 percent that is allocated to Washington?

A. Washington pays that.

Q. Well, does it -- go ahead. Sorry.

A. Sorry. So we allocate -- sorry. Maybe this is a little bit of a confusion here. So we take the generation associated with Chehalis and the emissions associated with that generation and the cost of allowances for that generation for the entire system and come up with a total cost. Some of that would be offset by the free allowances that are solely Washington-free allowances or no-cost allowances, but the 45 percent of those costs are allocated to -- to Utah.

Q. Okay. And maybe I just am a little slow here. All of the costs of compliance are imposed on the non-Washington customers; right?

A. That's correct.

Q. Okay. Are you taking whatever that dollar figure is on an annual basis and applying the SG factor to that?

A. I'm not sure I know what you mean by "that."

Q. So whatever -- whatever that dollar figure is. I was trying to keep us from having to do math.

A. Okay. Yeah.

Q. Whatever that dollar figure is. Let's say it's 100 bucks. I think it's quite a bit more than 100 bucks, but that's an easy one to use. Let's say the entirety of the obligation in any given year is $100. Are you allocating that $100 based on the SG factor, which would, I think, allocate $45 to the state of Utah?

A. And the $100 equals --

Q. It's the entirety of the costs that you have to incur to buy allowances.

A. I think we're doing the math differently. I think the result is the same. So we take the total Chehalis emissions times the allowance cost to get the total dollar amount, and then we allocate the 45 percent to Washington -- or to Utah.

Q. Okay.

A. But then -- so we might come up with -- well, maybe the math doesn't work out. This is why I don't do math on the fly. But we take the total emissions cost, allocate that out so that Utah customers are paying for the amount of their emissions and they are not getting the benefit of the no-cost allowances for -- for Washington customers. So again -- yeah. I don't want to do the math. I don't want to --

Q. Yeah. I'm really not trying to make you do complicated math here.

A. It's not that complicated. I'm just --

Q. No. At some point you have a dollar figure that needs to be allocated, and that dollar figure I'm asking you to assume is the dollar figure associated with acquiring paid allowances.

A. That's correct.

Q. Okay. And so how is that dollar figure allocated to the states? Is it pursuant to the SG factor?

A. Yes, that's correct.

Q. Okay. So, again, at $100, if the cost of buying allowances at auction is $100, you're saying that 45 of those dollars are allocated to Utah?

A. Yes, that is correct.

Q. Okay. And then what I was trying to get to is, if you have that $100, we said that under the SG factor 8 percent is allocated to Washington. I'm just curious what happens to the $8?

A. The $8 is never incurred because we would receive those -- and that's maybe where we're talking past each other a little bit. The $8 is never incurred because those allowances would be received from the Department of Ecology for Washington load.

Q. Well, but the $8 -- I mean -- but I've asked you to assume that the bucket of dollars is the dollars that you incur to buy allowances. So you're not buying allowances for the Washington retail load because you're getting the no-cost allowances from somewhere else.

A. Right. So that's maybe where we're talking past each other a little bit. That $100 -- if that's the dollars that we actually spent before we did the allocation, we would have to gross up to a number equal to all of our load. So we would say $108 that we should have purchased or would have purchased had all of our load been subject to this. The $8 is offset by no-cost allowances, and the rest of it is allocated out on the SG factor.

So the 8 percent -- I mean, now we're, like, messing up our math in our easy $100 number. So we would gross it up for the 8 percent. So maybe let's just say 92. So 92. We spend $92. We gross it up. Our allowance cost with Washington load would have been $100. 8 percent of that is allocated to Washington. So that $8 is offset by the no-cost allowances, and then of the $100, 45 percent is allocated to Utah. So $45 associated with the generation.

If you do -- if you allocate just the $92, all customers in other states are now benefiting from the free allowances, and we're not in compliance with Washington law that says they have to -- those free allowances or those no-cost allowances have to benefit just Washington customers.

Q. Well, the calculation that I think you're describing is you perform a calculation such that the costs of purchasing allowances are only allocated to the non-Washington states; is that right?

A. That's correct.

Q. Okay. So the costs that you incur are allocated to Utah -- like, if you're just looking at the costs that are incurred -- let's say it's $100 -- Utah actually pays more than $45 of those dollars, doesn't it?

A. I think you're going to have to walk me through how you get -- I know we talked a lot about the different numbers. I may be a little lost in our hypothetical scenario here.

Q. Well, what you indicated, I think, was you take the actual cost that you pay for allowances -- which, again, you're only purchasing for the non-Washington customers; right?

A. That's correct.

Q. So you take those dollars, and you perform a calculation to gross it up to try to eliminate or to try to ensure that the costs that are associated with those are only paid for by the non-Washington customers; right?

A. That's correct.

Q. Okay. And so in order to do that, while your actual costs are $100 of purchasing allowances, you perform a calculation such that it seems in the calculation like it's -- we'll use 108 -- I don't do percentages -- it seems like 108; right? So that the $8 that would otherwise be allocated to Washington are just attributed to the no-cost allowances so that the Utah customers are paying 45 percent of $108 instead of $100. Is that roughly how that --

A. Yes, sir.

Q. -- works? Okay.

But with respect to the -- I think this is the way that the math works. With respect to the actual dollars that you're -- you're incurring, Utah is paying more than its SG allocated share of those actual dollars because of the way that you guys perform that calculation; right?

A. Yes, that's correct, because they receive 45 percent of the generation of the benefit of that plant, and so if we were to do it on the net number as -- as we're talking about, they would actually receive a benefit of those no-cost allowances, and we would not be in compliance with Washington law.

Q. And I guess I'm failing to understand how Utah would get the benefit of the no-cost allowances without that calculation gross up. I mean, you've got -- all the costs of allowances are for the -- the allowances that you have to buy for non-Washington customers, and that gets you a dollar figure. What it seems to me is that you got to do the gross up so that when you allocate on the SG factor, you're not allocating any costs to Washington.

A. That's correct.

Q. Okay. Let's -- I walked up the 2020 Protocol. So let's -- you know, let's look at that. We looked at the SG factor a little bit, but let's go back to 3.1.2.1. We looked at that data request response in the Division's testimony where the Company indicated that the no-cost allowances are situs assigned to Washington under 3.1.2.1; right?

A. That's right.

Q. Okay. And is that -- to your understanding, 3.1.2.1 identifies three types of state resources that will be assigned or allocated as follows, and it identifies demand-side management programs and portfolio standards and state-specific initiatives; right?

A. That's right.

Q. And it gives a description. I've read them in a previous hearing. I don't think we need to do it here.

A. Yeah, sure.

Q. The -- the data response indicating that no-cost allowances are allocated situs to Washington -- is that because it's a portfolio standard or a state-specific initiative?

A. The -- the allowances are provided, and what the Department of Ecology has stated is that those allowances are provided to Washington load because of other portfolio standard laws that exist in Washington.

And so we disagree with this, and this is partially why we're, you know, in a lawsuit with the state of Washington, but they've said that, one, those -- those no-cost allowances can only benefit Washington customers, and then, two, the reason why they get no-cost allowances is because they have other portfolio standards that they have to -- that Washington customers have to comply with and those costs are of the -- of the portfolio standards are situs assigned.

Q. Okay. All right. I think that answered my question, and I believe that that is all. I appreciate it, Mr. Wilding.

CHAIR FENN: All right. Let's go back to Rocky Mountain Power. See if they have any redirect.

MR. KUMAR: I do. I have a few questions, Your Honor.

REDIRECT EXAMINATION

BY MR. KUMAR:

Q. Mr. Wilding, let's go back to the 2020 Protocol that we just walked through.

A. Yep. I'm there.

Q. Now, would you describe Rocky Mountain Power's, like, sort of requirement to purchase allowances for Chehalis generation? Let's look specifically at 3.1.2.1. They're not a demand-side management program, are they?

A. No, they are not.

Q. Do they fit into the category of a portfolio standard?

A. No, it does not.

Q. And can you provide some context as to why Rocky Mountain Power's obligation to purchase allowances for non-Washington customers is not really a portfolio standard?

A. This is a tax or a cost associated with the emissions of Chehalis, which is physically located in the state of Washington. A portfolio standard typically is a state-mandated or a state energy policy that says the utility will serve load within our state with a certain percentage of renewable generation.

Q. And the next sort of bullet point there states specific initiatives. Does the Company's obligation to purchase allowances for Chehalis generation fit into that state-specific initiative?

A. No. And why I say no on that one is if we read the state-specific initiative language, even just that first language, the costs and benefits associated with interim period resources -- so Chehalis definitely is an interim period resource per the definition. It's generating and providing energy during this period.

So if we were to interpret it as a state-specific initiative, we would say the cost and the benefits associated with Chehalis would be a state-specific initiative and not just the cost.

Q. And now let's turn to 3.1.7.
A. I'm there.
Q. Can you look at sort of like those lines 217 and 218 which talk about generation-related dispatch costs.
A. Yes.
Q. Is that more akin to the Rocky Mountain Power's obligation here?
A. Yes, I agree. I think in line 217, 218 -- this is under the section "Miscellaneous Costs and Taxes," and those will be described as follows -- generation-related dispatch costs and associated plant will be allocated on the SG factor. And so I think definitely could fit into that first bullet on 217. I think the other place where it can fit is in 232 -- generation and fuel related taxes will be allocated using the SG factor. So both of those are better fits

than the section that we previously read and looked at.

Q. Does the Company pay taxes and royalties on the fuel that it acquires to fuel its plants -- you know, the coal and the gas that's used to operate Rocky Mountain Power's plants?

A. Yes, it does.

Q. And do those taxes vary based on the amount of fuel that's consumed to operate those plants?

A. The total dollar amount that we pay, yes, does vary based on the amount of fuel that we use.

Q. And the Company also pays property taxes on the generating plants that are system allocated; isn't that true?

A. Yes, we do pay property taxes, and those are system allocated.

Q. And the amount of property tax that Rocky Mountain pays in a given year will vary based on numerous factors; correct?

A. That's correct.

Q. Now let's quickly discuss the actual structure of the Climate Commitment Act itself. Would you say that the Company kind of has two obligations under the Climate Commitment Act -- one for generation that is sort of exported from Chehalis and then a separate obligation because it serves retail load in Washington?

A. Yeah. We do have to comply with the carbon -- or sorry -- the Climate Commitment Act, both because we have a generating resource, an emitting resource in Washington. So we are an emitting entity. And then, two, because we have retail electric load in the state of Washington.

Q. And let's say that the Company did not have any retail electric load in the state of Washington but it still owned the Chehalis operating facility -- and this is true for certain -- the Company has operating facilities in states where there -- they don't have any load; correct?

A. That is correct.

Q. Would the Company still have the obligation to purchase allowances for Chehalis generation?

A. Yes, we would. And at that point we would have no no-cost allowances allocated to us.

Q. Okay. We have no further questions.

CHAIR FENN: Okay. Mr. Russell, do you have recross?

MR. RUSSELL: It will be very brief.

RECROSS-EXAMINATION

BY MR. RUSSELL:

Q. Mr. Wilding, can you turn to your response testimony line 438.

A. Yes, I'm there.

Q. In questioning from your counsel, you were walked through Section 3.1.2.1 of the 2020 Protocol and asked to kind of give us your views on whether it's -- the CCA is similar to a portfolio standard or a state-specific initiative. On line 438 you state, "The Washington legislature passed the Climate Commitment Act in 2021 to reduce carbon pollution"; is that right?

A. That's correct.

Q. And it's your understanding that's a goal of the -- of the law; right?

A. That's correct.

Q. Okay. And would that be a goal of the law even if the Company had no Washington generation?

A. That's correct.

Q. Okay. No further questions.

CHAIR FENN: Okay. We have a hard stop right now, and I know we hate to do this to you, Mr. Wilding, but we're going to have to ask you to come back on the stand after a lunch break. I assume we're going to have questions. I can almost guarantee we'll have questions.

THE WITNESS: It will be my pleasure.

CHAIR FENN: Okay. All right. We're going to take a break, one-hour lunch break. Thank you very much. Off the record.

(Recess taken from 12:00 to 1:03.)

CHAIR FENN: We'll go back on the record, and we appreciate very much Mr. Wilding's patience with us to have to not to be finished before the lunch hour. I know there's always some residual anxiety that remains when a witness has to remain on a witness stand perhaps longer than they thought. I think we're now to any questions of the Commissioners.

Is there anything else we need to raise before we see if Mr. Harvey has any questions?

Okay. Let's go to Commissioner Harvey.

EXAMINATION

BY COMMISSIONER HARVEY:

Q. Hello.

A. Hi.

Q. Since the earlier cross was on the Washington, I think I'll start there, but then I'll eventually get over to the hedging that you had mentioned.

A. Okay.

Q. I'd like to get a little bit of understanding about the lawsuits that surround both the Washington program and other states' responses to that program. From your testimony and from your answers today, I understand that PacifiCorp is suing Washington to say that we don't think this is a reasonable program; is that correct?

A. That's correct. The department of -- specifically the Washington Department of Ecology and -- yeah. So we have a lawsuit that went to federal court and was dismissed, and now we are appealing that.

Q. Okay. And just to deal with a few hypotheticals, if PacifiCorp prevails in that suit and, hypothetically, if Utah -- the Utah PSC approved collection of these charges, if both of those held, would there then be refunds?

A. You know, I don't know the answer to that. I don't know if that decision would be retroactive or if it would just be, you know, from that point forward.

However, what I -- what I'm comfortable committing to is that, you know, if we did collect any money -- any revenue from Utah customers, that rule was overturned or we received free allowances -- no-cost allowances for all of our retail load as a result of that lawsuit and we did receive money back, that we would return that back, you know, accordingly to any customers that had to pay that. So I don't know what the outcome would be, but I can commit that we would refund that money to any customers at the end.

Q. Okay. So I'm trying to understand PacifiCorp's actions at the current moment given the, I guess, legal box that they're in. PacifiCorp is essentially saying it is obligated to obey the law as currently upheld at the court level they're at. Therefore, they want to collect, but they don't think the law is reasonable or legal or whatever the legal term is. So they're trying to get it overturned. Is that a fair summary of PacifiCorp's current thinking?

A. Yeah. I think that's -- that's accurate. We disagree with the law as it's been currently, you know, implemented and -- so we are taking all of our -- we're pursuing all the legal avenues and everything that we can to overturn that law -- or perhaps not overturn the law but to have it enforced in a more fair manner. But as it stands today, it is the law, and regardless of what we think about it, we have to comply with it.

Q. And for other utilities in Washington, are -- are there other major utilities that have the same situation that PacifiCorp does where they have customers both in state and out of state and generation both in state and out of state?

A. Avista is probably the most similarly situated to us where they have customers in both Idaho and Washington.

Q. And do you know if they're participating in any legal action with respect to that law?

A. I'm not aware of any, but I can't speak for certain.

Q. Okay. That's fine. Thanks. All right. Excuse me.

I want to talk about how Chehalis is actually -- or find out how Chehalis is actually dispatched, and this goes back a bit to the questions you answered prior to lunch, but it would seem to me that at any given moment in time PacifiCorp probably doesn't know what the actual increment is that would be attached to Chehalis' generation because they're still in the process of buying allocations for that year. Is that correct or not?

A. I would say, yes, that's correct, but I would maybe just caveat that a little bit that we don't precisely know what the cost of allowances are going to be, but we do have some intelligence to, you know, make a fairly reasonable estimate. So we know what prior -- prior auctions -- what the clearing price was in those, and we also, you know, see the bilateral market and what's posted on the Intercontinental Exchange, or ICE. So we do have some intelligence to be able to come up with a good adder for the dispatch or a good, you know, carbon price for the dispatch, but yeah. It's not precise.

We're using the best information that we have available to come up with the best estimate that we can, and, you know, as -- you know, assuming that the law continues and with the more auctions we have, the more, you know, liquid and the more trades that happens of these allowances, the more information we'll have. But for right now, I mean, we can't get precise, but we get pretty close.

Q. Okay. And are any of the questions in this section of my questioning -- if it would implicate either confidentiality or the legal restrictions I'm talking about, just say, you know, "I can't answer that."

A. Okay.

Q. And it won't hurt my feelings at all. I'll try to rephrase.

Is the -- do you know if the intent or the way that law is written anticipates a declining number of allocations over time?

A. It does, yes.

Q. Okay. And this may -- may be a "cannot answer" question, but does PacifiCorp anticipate the price of those allocations to increase over time because of that decreasing availability?

A. I think, just generally speaking, you know, supply and demand, less supply -- or, you know, demand, less supply, that's a possibility, yes.

Q. Okay. And then given PacifiCorp's history with auctions to date, how much variability have you seen in the clearing prices? And, again, if that's restricted, tell me.

A. No. I think I can answer that.

You know, there has been a little bit of variability, especially this last year in the auction clearing prices. I think, you know, the first year that it was initiated in 2023 it was a little bit more stable, but folks were kind of trying to get used to it, trying to figure out how to do things. So we saw some fairly high prices. They came down a little bit after that.

And then during the 2024, this last calendar year, you might be aware, but there was a ballot initiative on the Washington state ballot to overturn the law, and then there was our lawsuit, and there was another lawsuit that was filed, you know, before ours. And so there was some uncertainty in the market and uncertainty in the -- in what the law was going to do, if that ballot initiative was going to pass. A lot of the polling was showing kind of a 50-50. And so we did see prices drop considerably in 2024, and then that ballot initiative did not pass, meaning the law continued, and we saw market prices -- or the auction prices tick back up.

Q. Are you able to give me an idea of how big of a drop on a percentage basis that was, or is that restricted?

A. No. I think -- I think those auction prices are public. It was about a 50 percent drop. So --

Q. And then going back to the -- the protocol -- the 2020 PacifiCorp Interjurisdictional Allocation Protocol, the language with respect -- I don't remember which number it was -- but with respect to situs assigned talks about assigning both costs and benefits.

A. Yep. That's on page 8 of the protocol, 3.1.2.1.

Q. Yes. Okay. And then language on taxes, which is, I guess, on page 10.

A. Yes.

Q. That just talks about allocating cost, essentially, because a tax is a cost; right?

A. That's correct.

Q. So my -- my question related to the protocol is the parties, each of the states that signed it plus PacifiCorp, were doing that in an environment of what existed at the time; right?

A. That's correct.

Q. And -- and this program -- the Washington climate Action Program -- is that --

A. Climate Commitment Act.

Q. Climate Commitment Act.

A. CCA.

Q. CCA. It did not exist at the time this was negotiated; correct?

A. That is correct.

Q. But there are several generation assets and various programs around the six to eight regions that are situs assigned; right?

A. Yes. That -- that's correct, and, you know, they typically fall into those categories that we -- that we discussed and those state-specific initiatives. You know, so, for example, the Schedule 32 and 34 customer programs in Utah -- those -- those are situs assigned. So it would be, you know, something to that nature where we are acquiring a resource to comply with a state program.

Q. Okay. So a final question on the Washington -- and this goes back a little bit back to what Mr. Russell was questioning you about at the end of his cross, and that was when you were talking about the 8 percent of Washington's costs. My question is what happens if the cost of buying the allowances is considerably different than the 8 percent would be?

A. And maybe I could maybe try to clarify what we were talking a little bit about. Maybe this might answer your question, but if not, let me know.

So if we just take the example using the 100 -- you know, say the Chehalis generation and the emissions equal 100 million metric ton of greenhouse gases. So, therefore, we are required to -- to retire -- sorry -- 100 allowances for the Chehalis generation. The way that we look at that is we say, okay, 45 percent of that 100 allowances are associated with Utah generation, and so Utah customers, you know -- the cost of that 45 allowances are included in Utah rates, and they should pay that. The eight allowances for the 8 percent of Washington -- those are offset by free allowances.

And so I think we're -- maybe the confusion was we don't take the dollars that we paid for the 92 allowances and allocate that out. We allocate out the allowance -- the cost of 45 allowances to -- so we don't take 44 percent or 45 percent for Utah for $92 and say each allowance costs a dollar. We take 45 percent of the total allowances and the costs of those are allocated to Utah.

So Utah customers are held harmless. They're not paying for any more of the allowances than the generation that they benefited from, and they're not paying for any less. And if they pay for any less, then we would be noncompliant with the Washington law.

Q. I think I might understand what you meant.

A. Okay.

Q. But I'm going to restate, and I'm going to change your numbers just a little bit, and tell me if what I've changed has caused a problem.

Assuming there's 100 million tons. So we need 100 allowances. Am I correct so far?

A. Yep.

Q. And that's total production.

A. Yep.

Q. Washington -- assuming that -- with your pre-compliance filing, you guessed correctly on the 100, Washington customers will get 8 allowances?

A. Yes.

Q. Correct?

A. From the state of Washington.

Q. From the state --

A. Yep.

Q. -- at no incremental cost?

A. That's correct.

Q. So PacifiCorp would need to buy 92 to be able to have a total of 100 to retire?

A. Yep.

Q. And then whatever the cost of that 92 is, that's the percentage -- or Utah's 45 percent or whatever the SG factor is -- that would apply to whatever the cost of buying the 92 is?

A. They would pay for 45 allowances because --

Q. I don't think so.

A. Well, I think --

Q. That's what I'm asking.

A. Yeah.

Q. PacifiCorp has to buy 92; right?

A. So 8 of those -- so we need --

Q. So they need 100.

A. 8 are Washington -- sorry. I apologize. 8 are Washington. 45 are Utah. So when we buy 92, Washington's -- not Washington. Excuse me -- Utah pays for 45 of the 92, Wyoming pays for 17, and Idaho pays for 6, California pays for 2, Oregon pays for 26, and Washington gets 8 free ones. The Company gets 8 free ones, or no-cost ones, for the Washington load. And then if I did my math right on the fly, we add up to 100. That should be pretty close to 100. It's supposed to be 100.

Q. I think we went this way, but it's fine.

A. Yeah.

Q. Okay. So but in terms of if I thought of dollars, whatever PacifiCorp paid for the 92 they had to buy. That's the number that actually gets allocated with the SG factor or not?

A. No, and that's perhaps what -- what we were talking about is -- so we paid for 92 allowances. And so we allocate the cost of -- of those 92 allowances, and we just multiply it by 45 percent. Utah customers would pay for something less than 45. So if we just say each allowance is a dollar, when we take -- when they pay for 45 allowances, which is their share of the generation, they would pay for $45.

But now if they're taking 45 percent of $92, they would pay something like $43, just rounding here. They would pay something like $43, which now means we've kind of essentially double counted the Washington no-cost allowances because Washington customers are receiving those no-cost allowances, but we -- but all of our customers are benefiting from that because they -- you know, because that reduction in costs got allocated to all of our customers. But Utah customers are held harmless because they're only paying for the 45 allowances that we need that is associated with their generation.

Q. I'm not sure you and I use the term "hold harmless" the same, but I think I know what you mean.

Okay. So -- so we pay 45 percent of 92 and 45 percent of eight, because, in PacifiCorp's view, we're getting benefits from that 8?

A. We have to buy -- we have to buy 92 allowances. Utah customers buy 45 of those. All the other states, besides Washington, buys 47. Washington gets 8 at no cost, and in total we've purchased 100 allowances -- or we purchased and/or received a total of 100 allowances.

Q. But -- but 8 of those were free?

A. Right. And we didn't charge anyone for those eight.

Q. I think you've charged us some for the 8. Here. If you said I spent $92, which is what in this hypothetical world you would spend, and typically Utah pays 45 percent of your spending, we would pay for 43 because that's 45 percent of the 92.

A. And then you would have benefited from Washington customers -- we would have double counted Washington -- so Washington allocation -- they would have received their allocation for free at the no-cost, and then Utah would have received, essentially, 2 free allowances. So if we're just saying the allowances cost $1, we are going to spend $92 for those 92 allowances, and we would -- we would charge Utah the $45 associated with the 45 allowances from their generation that was allocated to them.

Q. But $45 is 45 percent of $100?

A. Because we need 100 allowances.

Q. But you haven't spend $100. You've only spent $92.

A. But if we only charge you 43, then you're receiving the benefit of the free allowances because 8 of those -- we're -- we're not -- we're buying and/or receiving 100 allowances; right? 8 of those are no-cost allowances from the state of Washington. So if we take the $92 and we allocate out the $92 -- so if we just go through the math -- 45 percent to the state of Washington -- or to the state -- sorry -- state of Utah, that's $43, then we don't have -- let me -- sorry -- we're going to -- we're going to receive $43 from the state of Utah when we need to buy $45 worth of allowances because 45 -- your share of the generation was 45 -- 45 allowances that needed to be bought.

Q. I'm willing to leave it there.

A. Okay.

Q. All right. I'm going to turn to the hedging.

A. Okay.

Q. I'd like to understand a little bit of the physical system. How much transfer capacity, in terms of physical transfer capacity, exists between PacifiCorp's two balancing areas?

A. We have 16,000 megawatts of transmission rights, firm transmission rights, from PacifiCorp East to PacifiCorp West. 1,090 megawatts of that are network transmission rights over PacifiCorp's system, and 510 megawatts are firm point-to-point rights over Idaho power's transmission system.

Q. And is that both directions or one direction?

A. Just east to west.

Q. And what do we have from west to east?

A. We do not have any -- we do not have long-term firm transmission west to east, and so we -- occasionally, we will try to buy transmission in the short-term markets for that, but we do not have long-term point-to-point rights or network rights.

Q. Okay. So when you talk about purchasing power in the west balancing area to offset or replace or whatever term -- I heard several terms -- power in the east, it's not a physical offset if you have no transmission going that direction?

A. Well, it is a physical offset because we --

the net effect is the same. So if -- you know, when we looked -- we balance and we co-optimize our two balancing authority areas, and we operate as a single system. The vast majority of our generation is in PacifiCorp East. I mean we're blessed on this side of the territory with a, you know, strong thermal generation fleet. Some of the best solar in the country and some of the best wind in the country. So -- and because our generation -- a lot of our generation sits in PacifiCorp East, that allows us to have network transmission rights go into the west.

And so all things being equal, if we did not buy purchases in the west -- and talking about, you know, specifically about the summer where we do most of our purchasing activity -- you know, what we would have to do is reserve that transmission and send generation from the east side of our system west. But because we have the ability and we have access to both market hubs, and, you know, kind of speaking generally about the northwest and southwest, there's multiple points we can transact at, but generally speaking, we can, and we do -- we can look at the low-cost option. And if the low-cost option is in the southwest, we utilize our transmission, send generation west, and we transact in one of the southwest market hubs, Mona or Four Corners.

But if the low-cost option or the more liquid option is in the west, we can transact in the west at a Mid-C, purchase the power there, and leave that transmission capacity open and leave the generation here in PACE.

And so that allows us to flex our system -- that transmission capacity allows us to flex that system, and the effect is the same. And because most of our generation is on the east side of our system, we can send it west, but when we buy in the west, we can leave that generation home in the east which would have the same effect as if we just bought more in the east and sent it -- sent it west. But that flexibility -- it is a huge benefit to customers, and the bidirectional transmission capacity is not needed because the impact is the same and because most of our generation is on the east. So, you know, you just need the one direction.

Q. Okay. So, hypothetically, if I'm buying -- if -- if PacifiCorp is buying something in the pacific northwest to meet local load there, assuming they have the excess, they can sell energy on the east side to other customers to offset some of the costs of that purchase?

A. Yeah, absolutely. We can do that because of our transmission system. If we see -- if we have the length to serve our own load and we see opportunities in the price spread between two markets, we can take advantage of that price spread because of our load and resource diversity and our transmission system.

Q. Okay. But in the case where PacifiCorp is short, which, based on testimony in this and other cases, seems to be happening more often; right?

A. In -- yes.

Q. Okay. Then that offsetting financial transaction can't happen. It's just a way to try and cover the peak; right? Just by making excess purchases where we don't have the transmission -- I mean don't have the generation locally?

A. It's a way to -- by transacting at the lower cost market, we are lowering costs for all of our customers. So when we need to make a market purchase to cover our peak load and to ensure that we have, you know, enough resources to meet our system obligations, now we have the ability to do that in the least cost manner, and we can do that in the northwest. If we -- if we didn't have that transmission or we didn't have that flexibility, you know, we might have -- be forced to transact in a market at a higher cost.

Q. Okay. You've used the term "least cost manner" several times today, but in terms of the hedging program itself, the descriptions I've read in the testimony seems to be more concerned about covering peak as -- as the primary objective and then trying to do that at a lower cost than might, you know, typically happen, I guess, if you're trying to do it locally. Is that a correct summary or not?

A. Yes, but I wouldn't say those two, least cost manner and our hedging, is -- they're -- those two are used together. So we hedge for two reasons -- you know, guard against price volatility and also reduce supply risk. And so we're hedging for those two reasons to, you know, make sure that we have enough energy to cover our peak load, like you said, and we hedge in the least cost manner by having that access to multiple markets. We hedge at the lower cost and also the most liquid markets typically in the northwest, and our transmission system and our system as a whole allows us to do that.

So while hedging itself is not necessarily a way into -- to which reduce costs, it's a way to guard against certain risks. We do hedge in the least cost manner.

Q. Let me put this into terms that makes sense to my mind as an economist, and you can tell me whether they make any sense to you.

A. Okay.

Q. I would say that you have these two objectives you've mentioned, guarding against price volatility and the supply, and that in the short-term you try to find the lowest cost manner of meeting those two objectives?

A. Yes, that makes sense to me.

Q. Okay. But the -- and then here's my secondary question. See if this is a fair characterization. The Company isn't necessarily doing that in the long-term, in terms of saying what's the least cost long-term manner of doing that. They're more focused on these two short-term objectives -- supply, reliability, and price volatility.

A. I disagree that we're not doing that in the long-term. You know, that's not my responsibility at PacifiCorp. My responsibility is essentially real-time to three years out, and so we're looking at the near term, near reliability, those things that you mentioned, but from a long-term system planning, you know, we have the integrated resource plan and the action plan and all those things that go along with that, and they are also looking at planning in a, you know, cost-effective manner over the long-term.

So my -- my focus is on kind of real-time to three years out, but there's a whole other team that's focused on the long-term resource plan for PacifiCorp.

Q. I certainly understand that, but I guess my question is -- I should have been more precise, but with respect to your responsibilities and your expertise, it's short-term?

A. Yeah. Three years out and in.

Q. Yeah. To define short term is when you can change a major variable, and certainly you can't change much major variables in terms of the amount of generation or something in the system in three years?

A. Correct. Yeah, correct.

Q. Okay. All right. So just a final clarification question going back to Washington, and I apologize for that, but the benefits are situs assigned and the costs are system assigned as a general concept with respect to that program. Would you agree with that?

A. The -- if by benefits you mean the no-cost allowances?

Q. Yes.

A. Yes. I -- the no-cost allowances are situs assigned to Washington to comply with Washington law. The benefits with -- from the generation and the megawatt hours -- those are per system assigned, system allocated.

Q. The costs associated with that second category of benefits are system assigned?

A. Yes.
Q. Okay. Thank you. That's all my questions.
CHAIR FENN: Thank you, Commissioner Harvey.
Commissioner Clark, do you have any questions?
COMMISSIONER CLARK: I have a few. Thank you.

EXAMINATION

BY COMMISSIONER CLARK:
Q. Good afternoon, Mr. Wilding. I think I'm going to ask you some questions to begin that -- that you answered during the general rate case as well.
A. Okay.
Q. But to -- to sort of incorporate that foundation into this record, I want to ask you about Mid-C and the superior liquidity that exists in that -- at that market hub, as opposed to the southwest hubs -- I'll call them hubs at least.
A. Yeah.
Q. And would you be able to quantify that in some way? Give me some sense of, rather than qualitatively, what is the difference in the liquidity, and how does that affect the pricing?
A. Yeah. I do have a chart in my testimony. I'm trying to remember which testimony it was in. So if you just give me one minute, I can point you --
Q. Sure.

A. -- there. It's page 15 of my response testimony.

Q. Okay.

A. Line 294. And you see the --

Q. Yep. Thanks.

A. These are the trading volumes that are -- that are reported by ICE, the Intercontinental Exchange between Palo Verde and Mid-C. We use Palo Verde as kind of the proxy for the southwest. There's obviously other hubs there. There's Four Corners, there's Mona, Mead, and we do transact at those market hubs as well, but the liquidity is so small there that ICE doesn't even publish information for those. So PV is kind of representative of that. So --

And then on the price, I think, just to answer your second question, in my surrebuttal testimony -- just one second to find that as well. I mean -- and one thing is liquidity is important because it really doesn't matter what the price difference is if you don't have any sellers, but, you know, just take one moment to find that price.

Oh, on -- and this is confidential; so I won't say the prices, but I'll just point you to where it is in my testimony.

On page 7 of my surrebuttal testimony, that whole paragraph, starting on line 141 to 147, does show when we were -- we did buy a few -- we did have a few purchases in the forward market on the east side of our system, and it shows what the price difference is between the east side of our system what we bought at, and what we bought at on the west side of our system.

Q. Right. That's helpful. Thank you. I can see that.

So with that in mind, I want you to turn to page 10 of your response testimony. Here you've got a chart of Palo Verde hourly prices from 1/1/2019 to basically the end of 2023; correct?

A. That's correct.

Q. And I think the purpose of this chart is to demonstrate volatility; is that right?

A. Yes, that's right.

Q. If I -- if I look at this chart in relation to the chart on page 15, it seems to me that there's some -- there's not -- there's some correlation, but there's also some pretty significant divergences in the direction, and so I'm just wondering why you use the chart on page 10 rather than a Mid-C chart.

A. You know, I think I would be happy to provide a Mid-C chart if that's helpful. I can understand why the -- you know, why that would be of interest to you, but we would be happy to provide that as well. I think it would still show the price volatility that we're seeing in the market.

Q. If we look at the Figure 1 on page 10, either for the Palo Verde hourly prices or the Mid-C prices during this time frame, have you quantified what your net power costs would have been if you had simply purchased whatever requirements existed at whatever time in the spot market as reflected here to compare that to the net power costs that you incurred in 2023 under your hedging strategy?

A. No, we haven't. And the reason why is it's -- you know, that counterfactual would be, you know, really almost impossible to -- to calculate because, you know, we are a significant sized utility in the west. We're a significant player. So if we were to, you know, purchase all of that in the spot market, all of our requirements in the spot market, it's likely that -- and it is true, that we would have an impact on price. So we don't know what the price would be if we were out buying all of our requirements in the spot market.

And then the other thing is just --

Q. Could I -- before you give me the other thing --

A. Yeah.

Q. -- I want to correct an assumption that I may have incorrectly stated. I'm speaking of just the marginal piece that you would require to address the -- you know, the peak requirement beyond your abilities to generate in the east and supply the east load.

A. Yeah. And I am as well.

Q. Okay.

A. So even -- even just buying that incremental piece would be significant enough that we could potentially move the market. And then --

Q. But wouldn't -- wouldn't it be worth -- I'm sorry I'm interrupting you. Finish your answer.

A. And then from a reliability standpoint, we have seen a significant decline in the real-time bilateral market since EIM has been implemented over the last decade and as more entities have joined the EIM. And so for me, personally, that is not a risk, to carry an open position into real-time or even the daily market, that I would ever suggest that the Company takes because that will put reliability and would introduce severe supply risks to the point of potentially losing retail load and having to have rolling blackouts. So that's a risk I personally would never take or suggest be taken.

And then to the point about -- to kind of further that point, talking about the hourly market and the bilateral market kind of losing liquidity since EIM has been in place -- also, to participate in EIM, which provides a significant reliability benefit to the Company and to its customers, you have to go into that market with the ability to serve your own load. And then the market footprint is re-dispatched, and you can, you know, create benefits that way by the more economic dispatch that incremental changes during real-time, and we have seen a significant reliability benefit from there.

That -- so not only -- so it just -- that -- if we don't -- if we leave that position open and we go and do kind of what you're suggesting, not only do we run the risk of -- of blackouts and rolling blackouts, but we also lose the tools that we have to be able to, you know, reliably serve the system, a huge tool in EIM.

So, no, we have not done that. I don't think it will tell us anything informative, and with the reliability risk on top of that, that is not a risk that I would ever suggest taking.

Q. I understand how reluctant a utility can be to the prospect of vulnerability to rolling blackout or some extreme event, but I'm trying to weigh that against the -- the magnitude of the increases in net power costs that we've seen in the last three years and just wondering whether at least some kind of counterfactual analysis ought to be -- be undertaken to -- as a way of exploring other -- other ways to address volatility that we're seeing in the orders of magnitude that we're experiencing it. Do you have any ideas about what could be done?

A. Absolutely, and we are doing things, and we are trying to, you know, do our best to combat some of these things. You know, besides reliability -- reliably serving load cost is, you know, the number one thing that I think about and doing this in a way that's most beneficial to our customers.

So a couple of things that we are doing -- you know, we're constantly looking at the tools that we have available to us to ensure that we are, you know, providing customers with a -- and serving customers in the least cost manner, the lowest cost that we can. We've recently updated our optimization model to be able to include more variables and to run from day-ahead all the way through real-time, and we're really excited about that. That will allow us to manage our uncertainty requirement a little bit better and more precisely, which should result in customer savings.

We've been, you know, out in front of, you know, market expansion for the western United States. Not only were we the first ones to join the Western Energy Imbalance Market, or EIM, with the CAISO, and we've seen that grow to, you know, produce over $5 billion of benefits. You know, just under 100 million of that -- or sorry -- just under a billion of that is PacifiCorp's -- for PacifiCorp's customers over the last decade or 11 years.

We're, again, leading the west on further market expansion to the extended day-ahead market, EDAM, which will allow us to, you know, further benefit from the market optimization. And so instead of just optimizing the kind of incremental changes within the hour and the changes that a plant can make within the hour, now we can optimize among a larger market footprint day-ahead decisions and commitment decisions and dispatch -- you know, dispatch schedules way better than we can with EIM. And that's going to produce -- again, our models are showing hundreds of million dollars of benefits.

Some of the other things that we're doing is, you know, we're adding resources. We just added 1,500 megawatts of wind resources in eastern Wyoming with a transmission line that drops right into Salt Lake City, right into Utah, and that transmission line has allowed us to, you know, export even more wind out of Wyoming and allowed us to manage the entire Wyoming transmission system better.

We are also -- focusing on the capacity needs that we have going forward and in 2026, we're going to bring on about a thousand megawatts of batteries that will allow us to shape our purchases much better. And so instead of having to purchase, you know, a 16-hour block to cover off the four hours that we need the electricity, now we can use that excess electricity from solar and that we have during the day charge the battery and discharge it over that four hours that we need it.

And -- and then there's one other thing I was going to point out, but I can't remember what it was.

But the point is we're doing stuff. We're trying to -- to -- to manage this, and, you know, the step changes that we saw in the electricity markets are a lot of the same things that we saw in our everyday lives with inflation and supply chain challenges. You know, there was a lot of -- a lot of generation that was meant to come online during the pandemic that -- you know, couldn't buy solar panels or you couldn't buy the components to build the batteries, and so those were pushed out.

And so what we really saw was, you know, during this time, we saw loads growing faster than anticipated, resources coming on slower than anticipated, and we saw scarcity market pricing. I think in the last -- in 2024, you know, we saw more generation come online and some of that to start -- start correcting itself. But -- and these are the ebbs and flows of markets, but, I mean, all this considered, I think we are doing a lot to try to serve our customers in the least cost manner without putting them at risk for not being able to serve their load.

Q. With respect to EIM, at least, that's an area where the Company does go to quite significant lengths to be able to at least produce what it represents to be a counterfactual scenario so that the savings can be understood somehow from that. And so I'm just coming back to why wouldn't it at least be productive to understand what would have happened if I had done nothing? And -- and that -- perhaps that would lead to -- to approaches that you haven't considered yet.

As far as you know, Mr. Wilding, does that -- that -- does anyone in this record make an attempt to -- any witness, any exhibit -- to demonstrate what the outcomes would be if we -- if -- if the Company had simply met its peak requirements with spot purchases?

A. Not that I can recall, that that analysis has been done.

I will just say the EIM benefits are calculated by the CAISO and not the Company. Just one thing there. And then, again --

Q.   I guess publicized by the Company certainly. You would accept that, wouldn't you?

A.   Yeah but --

Q.   Okay.

A.   Okay. They're on the CAISO website.

Q.   Sure.

A.   But we do use those and rely on those.

Q.   Sure.

A.   I think we're kind of just fundamentally talking about something different here, though, where there's really two variables that we don't know and don't control and would likely be impacted if we did not transact in the forward market, and that's market liquidity and market price. So even if that analysis came back and said, hey, you could serve load, you know, cheaper by relying on the spot market, that's not a risk that I would be willing to take.

Q.   Understand.

A.   Because of that -- and to make it even worse, the days that you're going to have blackouts are the hottest days of the year when people are relying on their air-conditioning or the coldest days of the year when they're relying on electric heat in the northwest or, you know, those types of things.

And so that brought -- jogged my memory that the one other thing that we can do and that we have done is, you know, we are starting to see the liquidity a little bit more on index-priced products, index-based products where we can lock in the physical capacity, but we have the ability to let the price float with the -- the spot price. It comes at a -- it typically comes at a premium to the spot price, you know. So we have done some of those as well, and I'm probably getting into confidential information. So --

Q. Well, I appreciate your -- your lengthy answer, and it is helpful.

A. Thank you.

Q. Honestly. I -- I wrestle with -- with the outcomes that this regulatory mechanism is achieving. And, as you know, for about ten years, there was a pretty narrow set of outcomes, largely, with, I think, one exception, some remaining payments or costs that customers needed to absorb that represented the difference between NPC that was in base rates and what was actually experienced by the Company. But then suddenly in 2021, that happens to coincide with the change in your hedging policy, that average outcome -- which I -- I think is about $19 million or something like that a year -- is suddenly almost five times that, and then the next year it's -- it's, you know, eight or ten times, and then the next in 2024 it's 20 times.

So that -- do you -- would you agree with me that it's reasonable for the Commission to be really wondering about the efficacy of the EBA and how this subject might be approached in a more effective way for -- really for the Company and for customers so that -- so that the really challenging and controversial set of factors that we're dealing with today could be at least somewhat avoided and we could return to the -- the kinds of experiences that -- that we were used to between 2010 and 2020?

A. Well, I -- I hear the -- yeah, I hear your concern, and I definitely understand that concern. I think I would maybe just say a couple things -- is, one, that, you know, correlation does not, you know, imply causation. And -- so our changing of the hedging policy was, in fact, to respond to what we were seeing in the market and the scarcity of resources and what was available.

And if you remember in August of 2020, California did have rolling blackouts because of a, you know, supply situation where they did not have sufficient supply to serve their load. And so we saw that. We saw the pricing, the volatility, and we made our changes in -- in response to the market. So the correlation is us responding to the market, not causing the changes in market.

I think over the last couple of years, we've had this kind of unique set of circumstances where, you know, I'm sympathetic to the results, but we had, in our last general rate case, kind of, you know, pre-pandemic baseline net power costs set based on what we knew at the time that was, you know, significantly lower than what we're seeing today. And we've had a -- no doubt about it -- we -- this is not a gradual increase of power costs, but it was a step change in power cost, and so we're not the only utility that has felt that step change.

And, you know, over the last couple of years, we've really dealt with some difficult situations. We've dealt with, you know, coal supply issues, where, in the past, always considered coal super steady, you know, super reliable, but then there's a fire at the Lila Canyon Mine that caused, you know, not only price issues, but also, you know, supply issues with coal. Had a bad hydro year. You know, all of these things kind of compound on itself and plus the new resources not coming online like I stated, and you see a step change.

And so while the -- the amount of the variance, I understand, is -- is not desirable, but I -- the EBA is working as it's supposed to. It's supposed to, you know, provide that ability to recover the variable costs that are incurred to serve customers load, and the exact opposite is true. We've had years where we've, you know, returned a credit to customers because the baseline was higher than what actually happened.

And, you know, if I -- I don't know for sure, but based on what I've seen, you know, I think we'll start to see leveling out of power costs. I think, you know, we're getting back to -- I don't want to say back to normal, but, you know, back to more of a steady state as opposed to, you know, dealing with the resource scarcity. You know, we see batteries being added all over the western United States. New wind come online, and I mentioned with us, new transmission lines. All of these things help.

I think we just went through a really hard period with a low baseline of net power costs set before the pandemic and a step change in power costs that not only we -- I can't stress this enough. It's not just utilities that face this. I mean, the same thing that caused inflation and, you know, supply chain disruptions that we all saw in our personal lives -- those are the same things that are causing a lot of, you know, changes in the electric market as a whole plus the coal issues that I mentioned.

Q. Those are all my questions. Thank you.

A. Yeah. Thank you.

CHAIR FENN: Thank you, Mr. Wilding, for your responses to Commissioner Harvey and Commissioner Clark's questions. I don't want to beat this into the ground, but I just have a couple of questions to follow up on what was asked.

EXAMINATION

BY CHAIR FENN:

Q. So when the Company changed its hedging program in -- I think July of 2021?

A. Mm-hmm.

Q. Were you one of the decision makers on that change of the hedging program?

A. Yeah, I was. And one of the reasons I think I've mentioned it in testimony -- one of the main reasons is, you know, we saw the scarcity in the market. I mentioned the blackouts in California in August of

2020. You know, we saw those -- those market conditions. We knew that we had an open position that we needed to fill, and based on the financial metrics that we were using, our hedging policy was telling us to sell energy when we needed it the most.

Q. Okay. Can you give me just the shortest summary as possible as you can the difference between the pre-July 2021 hedging policy and then the post-July 2021 hedging policy?

A. Yep.

MR. KUMAR: Chair Fenn, I just want to caution. I'm a little worried we might be getting into confidential information here. I think we're happy to get into it. I just want -- because the details on the hedging policy and how we purchase those --

CHAIR FENN: I don't think I need a lot of detail.

Q. (BY CHAIR FENN) My understanding is -- maybe let me state -- this is an oversimplification, but let me see if this is correct. That in the pre-2021 you use the TAYLAR [ph] or TVAR [ph] values to determine average energy positions; is that correct?

A. Correct.

Q. And the post-July 2021 you were shifting from average energy positions to peak hour requirements; is that an accurate description?

Answer without disclosing any confidential information. If that's -- was it a fair question, or is there a question -- do you have a problem with the question? I can rephrase it.

MR. KUMAR: And I will defer to Mr. Wilding on this, but based on how we've marked the various methodologies in the testimony, I think the actual disclosure of those methodologies and those metrics may be confidential. And so I just want to be very careful about it because the disclosure of those metrics could, in fact, like, provide information to the counterparties that were trying to conduct those hedging transactions with that we don't want them to have that information to use against us to essentially raise the costs that we would pay.

CHAIR FENN: And I appreciate that.

Q. (BY CHAIR FENN) All I want to ask is that -- I don't want any metrics. I just want to know if the concept is accurate -- that we're shifting from an average energy position to peak hour requirements. Is that accurate?

I grant you it may be an oversimplification, but to the extent -- do you disagree with that characterization?

A. It is an oversimplification. There's a lot of nuance, but, yes, that is accurate.

Q. Okay. All right. And that's all I'm going to get into it. I just am trying to make sure I understand the basics of the program without -- without the metrics, without the nuances, and I'm going to move off of that if you're okay with it.

MR. KUMAR: Well, I think we're happy to get into it, and we're happy to have Mr. Wilding explain more about it if that's where you want to go. I just think we -- we're happy to do that in confidential session.

CHAIR FENN: Okay. All right. Let's see if I get into a question that you feel like you want to go -- ask to go into confidential session. I don't think we will.

I'm just -- I want to understand, and I'm going to refer to -- if you'd like to get a copy of it -- I'm trying to do this as fast as we can here -- DPU Exhibit 1.1 in their direct testimony. It's the 2024 EBA audit report for Rocky Mountain Power.

Do we actually have a copy of that that we can give to Mr. Wilding?

MR. KUMAR: May I approach?

CHAIR FENN: Yes, please. Yes.

Q. (BY CHAIR FENN) It's also on page 9 of -- yeah, DPU's Exhibit 1.2, page 9 of your testimony, but I'm referring to the exhibit also found in the testimony.

A. Sorry. Can you give me the --

Q. Yeah, page 7 of the Exhibit 1.1. DPU Exhibit 1.1. You see a DPU Table 2 there.

A. Page 7?

Q. Yeah.

A. Okay. Got it.

Q. Okay. So Commissioner Clark referred to these significant increases in net power costs, and I'm -- I want to ask a question about the -- in 2020 you can see we go from -- I'm just going to round this -- 6.6 million NPC; 2021, 90.6 million; 2022, 175 million; and in 2023, $455 million.

What I'm trying to understand is if that increase in those -- the magnitude of those increased costs are due simply to the volatility in the marketplace of the -- of the pricing transactions you were able to enter into, or are there other factors associated with it?

A. Yes. There are other factors. We've had, historically, bad hydro years with significant droughts. We've had the coal supply issues that we've discussed.

Q. But all of those would lead to pricing volatility; correct? Price increases, essentially?

A. Right.

Q. Okay. All right. And so are there any other factors that -- that led to those, you know, unprecedented increases in the last three years?

A. Well, when you're talking about increase, are you talking about the EBA recovery amount increases?

Q. Yeah. The EBA -- third column there, the EBA recovery amount increases from 6.6 million in 2020 to 455 million in 2023, with pretty significant increases in 2022 and 2021.

A. Yeah. I mean, I think, like I said, we -- we experienced in the country and the region experienced a step change in the market during that -- that time, and we had set a base net power cost in a rate case. And so, I mean, the EBA recovery amount -- it all depends on what the base amount is.

Q. Sure.

A. I mean, I accept that net power costs have been increasing over the last couple of years leading up to '23 and in '23, but we also had a base net power cost that was, you know, years old. And had we reset that cost and -- and re-forecast that amount, the EBA recovery amount would have been less.

Q. And I understand that position. I appreciate you sharing that.

I guess what I'm trying to get at is your response to what I think is the Division's position, and I will refer to it on page 6, paragraph 12 of the exhibit. And it states -- I'm looking now in the fourth sentence of paragraph 12. Do you see that there? Can you read that into the record?

A. The fourth sentence?

Q. Yeah. I think it begins, "The new program."

A. The new --

Q. Maybe it's the third sentence. Let's go through it again. It is the third sentence. I apologize.

A. "The new program has drastically increased the Company's hedging market purchases and costs contributing to the large EBA deferral starting in 2021 and are shown in DPU Table 2. All values are Utah allocated."

Q. Okay. So the question I have is did the change in the hedging policy contribute at all to the -- they're -- they're saying here that it drastically increased costs contributing to large EBA deferrals. I assume you reject that position?

A. Yes.

Q. But my question is a little simpler, and that is do you believe that the change in the hedging program, the way you went about hedging after July 2021, resulted in a larger NPC element in your -- in your hedging management?

A. No. And the reason why I say no is, again, it goes back to we changed the policy to address the risks that we saw in the market in not having enough energy and our old hedging policy, based on, you know, solely financial metrics, telling us to sell at times when we needed the energy the most.

And so no. I think -- I think the increase in costs is driven by external market forces, and we have acted prudently and hedged and purchased in a just and reasonable manner to reliably serve our customers.

Q. And I -- I understand your testimony on that. I guess I'm trying to understand why the Division takes the position. We can ask their witnesses, but their position is, is that the change in the hedging program resulted in increased costs.

Let me ask it this way. If you had not changed the hedging program and had kept the pre-July 2021 hedging program in place, do you think that would have then resulted in lower EBA NPC recovery amounts?

A. No. It's hard to say. We would have been much larger purchasers in the daily in the spot markets. It's hard to say what the spot markets would have done. We would have -- and there's likely times that we wouldn't have been able to serve load. I mean -- so I don't know. I can't say that with any certainty, but I can say that maybe costs would have been lower, but we wouldn't have served load in all hours.

Q. Yeah. Based upon the inability to purchase on the spot market because of unavailability or whatever reason?

A. I mean, and like I said, our coal plants -- we -- we didn't have coal. We were trying to preserve coal for those hottest days in the summer and trying to buy in the other hours. So I think like -- yeah. I don't know what costs would have done if we would have done something different, if we would not have bought in the forward markets. I do know we would not have -- like, it would have been much harder to reliably serve load and likely that we would not have been able to reliably serve load.

Q. Okay. All right. Thank you for your testimony in that -- in that respect.

So I guess the conclusion that you would hope the Commission would draw is that the significant increase starting in 2021 was due to the circumstances in the market we found ourselves in with all sorts of different conditions with price volatility which resulted in an increased price to you and the longer term contracts that you were entering into. That was the reason, rather than the change in the hedging program for the -- for the significant changes that occurred almost simultaneously in time with the changes in the hedging program. Is that --

A. Yeah, absolutely. And I just -- we changed the hedging program based on what we were seeing in the markets to address the risk that we were seeing in the markets. If we hadn't have changed the hedging program and kept the hedging program that we had before, it's likely that we're sitting here having a different conversation and you're asking me why I didn't change the hedging program.

Q. Yeah. No. I understand your position on that, that we might be having a different conversation.

I go back now to one question, though, that's kind of troubled me since Phase I of the general rate case. The Division uses this word, and they use it advisedly. They say that you unilaterally changed the hedging program in 2021 and didn't consult the Commission, and I'm just -- I mean, I'm not suggesting that you didn't have the right to do that. I guess I'm asking the question as to why didn't you -- if this was a major change --

A. Yeah.

Q. -- in the way you operated your hedging program, which it clearly -- as you now see the results, it is, why -- why wasn't there some notification or involvement of the -- of the Commission in that process?

A. Frankly, the fact that we -- I mean, frankly, that statement that we unilaterally changed the hedging program is just simply not true. I came out. I traveled to each of our six state commissions, and I gave presentations on what we were going to do and gave them -- gave everyone an update on how we were going to do it, asked for input.

In fact, when we came here to Utah, we said, "These changes are not yet been implemented, but these are the changes that we are going and that we want to make, and these are the reasons why," and we asked for input. We got told to, you know, put it in the semiannual hedging report, which we did. I don't believe that we got any feedback as to what we should do differently.

And once we went to all of the commissions, went to all commission staff and the DPU, all six of our states -- myself, Mr. John Fritz, who's our director of risk management -- we went and we did that presentation for everyone. And once we did that, we followed our internal processes to -- to implement this. And so we did not do this unilaterally, and this was not a change that was a surprise to anyone. I sat right over there in that room across the hall and gave the presentation.

Q. Okay. And I very much appreciate that explanation because this is all new to me. As you may know, I've been on this Commission eight months. So this all predates my involvement, but did you have those -- so -- and I didn't phrase -- "unilateral" is not mine.

A. I understand.

Q. That is in the testimony. I'm trying to explore it, though. But you're now telling me that you had discussions -- did you have discussions with the DPU or the Commission members in Utah or the Commission staff in Utah? Because I -- I'm not aware of any.

A. Yeah, I understand. You know, I want -- I think I recall Commissioner LeVar being in that room -- Chair LeVar being in the room while we had that, but I can't recall that with 100 percent certainty. I would have to go back and look.

Q. Okay. Well --

A. But I've done a lot of presentations here.
Q. Sure.
A. So --
Q. But from what I'm gathering you're saying is that you're -- I'm going to use this -- these are my words. You were -- you were not trying to spring something by surprise on any state commission. You were trying to disclose what the plan was and provide enough information so that this Commission or any other commission was notified to what was going on?
A. Absolutely, yes, sir. And also provide input if they had it.
Q. Okay. And I can't vouch and I'm not the right person to ask questions as to what that process -- because I wasn't here.
A. Yeah.
Q. Okay. I have one other question for you with respect to an assertion by -- in this exhibit. This is on page 7, and I just wanted you to respond to this. It's the paragraph right before DPU Table 2.
"The Company's decision not to model proven resource types and focus planning on other priorities have largely limited its procurement activity to intermittent resources, leaving it to rely on more extensive hedging market purchases during key hours was

a major driver of the 2023 deferral."

Would you like to respond to that -- whether that's true, whether it needs to be qualified, or whether it's not true?

A. You know, again, the IRP and the long-term planning is not my expertise, but, you know, I don't believe this is true as well -- either. You know, I know the IRP is a robust process that looks at many different scenarios and options to arrive at a preferred portfolio.

You know, I know in 2020 we added significant amount of wind resources in Wyoming along with a transmission line to move that wind resource -- those wind resources to load. We added more wind resources just recently at the end of last year and beginning of this year, and with another transmission line we're adding batteries in 2026.

I mean, as you are aware, resources take time to plan and to build. And, you know, I think, as you are also aware, some of the challenges that we saw the last couple of years, you know, and the pandemic itself, was not foreseen, and, you know, load grew faster than we forecasted. We did not foresee the coal issues, and, you know, even if we would have had another coal plant to use, we wouldn't have had the coal to burn.

So, you know, these are all -- this is way too simplification of the issues that we faced.

CHAIR FENN: Okay. All right. I wanted to get your response to that.

Mr. Wilding, I think you've been very cooperative on staying on the stand another hour and 25 minutes after lunch when I didn't expect it was going to be that long, but we will now -- we'll excuse you. Is there any other -- okay.

THE WITNESS: Thank you.

CHAIR FENN: Thank you, Mr. Wilding, for your testimony today. I appreciate it.

All right. I -- I think that -- that's all your witnesses; is that correct?

MR. KUMAR: That is correct.

CHAIR FENN: Okay. Let's turn to the Division of Public Utilities and let you call your first witness.

MR. GRECU: Thank you. The Division calls Mr. Gary Smith.

CHAIR FENN: Mr. Smith. Welcome, Mr. Smith.

THE WITNESS: Thank you.

CHAIR FENN: Thank you. Please raise your right arm.

GARY SMITH

was called as a witness, and having been first duly

sworn to tell the truth, testified as follows.

CHAIR FENN: Thank you very much. You may proceed.

DIRECT EXAMINATION

BY MR. GRECU:

Q. Mr. Smith, could you please state and spell your name for the record.

A. Gary Smith, G-a-r-y S-m-i-t-h.

Q. By whom are you employed, and what is your position?

A. The Division of Public Utilities, and I'm a utility technical consultant.

Q. And what is your business address?

A. It is 160 East 300 South, Salt Lake City, Utah.

Q. And have you participated in this docket on behalf of the Division?

A. I have.

Q. Could you briefly describe your participation in the docket.

A. I was sort of the lead in analyzing, reviewing and -- both testimonies and also information submitted by the Company and also obviously testimonies provided by other parties.

Q. Did you review the Company's filings in this

docket as well as the filings from other parties?
A. Yes.
Q. Have you also reviewed the responses to data requests?
A. I have.
Q. Did you prepare and cause to be filed your direct testimony and DPU Exhibits 1.1 Dir through 1.8 Dir on November 5th, 2024, and your rebuttal testimony and DPU Exhibit 1.1 R filed on January 8th, 2025?
A. Yes.
Q. Did you also prepare and cause to be filed your corrected rebuttal testimony, in clean and red-lined versions, and the corrected DPU Exhibit 1.1 R on January 15th of this year?
A. Yes.
Q. Do you have any changes or corrections to those filings?
A. Nope.
Q. And if I ask you the same questions posed in your direct and corrected rebuttal testimonies today, would you provide the same answers?
A. Yes, I would.
Q. Do you adopt your prefiled direct and corrected -- corrected rebuttal testimony as part of your testimony today?

A. Yes.

MR. GRECU: At this point I'd like to move to admit Mr. Smith's direct testimony and corrected rebuttal testimony and associated exhibits.

CHAIR FENN: Seeing no objection, we'll admit Mr. Smith's direct testimony with the accompanying exhibits, his rebuttal testimony and exhibit, and corrected rebuttal testimony and corrected exhibit. Thank you.

(Gary Smith's prefiled testimony and exhibits were admitted into evidence.)

Q. (BY MR. GRECU) Mr. Smith, have you prepared a summary to share today?

A. Yes, I have.

Q. Please proceed.

A. Thank you. Good afternoon, Chair Fenn and Commissioners Clark and Harvey. Thank you for the opportunity to address Rocky Mountain Power's, or the Company's, request for cost recovery and the Division's report in the Company's 2024 energy balancing account or EBA filing.

On May 1st, 2024, the Company filed its application requesting recovery of approximately 455 million in net power costs for the deferral of 2023. This is the largest deferral requested by the Company.

The Company's reasons for the increased costs include the following: decreased coal plant generation compared to the EBA base, or base, established in 2020 due mostly to coal fuel supply issues; underperforming wind plants; unrealized production tax credits and hydrogeneration lower than base; increased reliance on expensive replacement power for market purchases made at higher average market prices than base, resulting in the largest increase in the EBA deferral; increased natural gas fuel expense due to higher average prices that assumed -- that was assumed in base; and the largest wholesale sales volume -- or sorry -- did I say that -- the lowest wholesale sales volume since 2021 due to the lack of available Company plant generation.

On June 28th, 2024, the Commission approved an interim rate recovery of 431.6 million commencing July 1st, 2024.

After reviewing the Company's application for cost recovery, filed testimony, and information provided in response to data requests, the Division calculated an updated total Utah-allocated EBA recovery of 334.5 million for the calendar year 2023, an increase of 57.7 million from the calculated recovery amount included in the Division's November 5th, 2024, report and direct testimony.

The Division's total updated recommendation of 334.5 million is 97.1 million less than the approved interim rate recovery amount due to the following recommended adjustments:

All numbers are Utah allocated amounts and include accrued interest.

A 629,000 adjustment for a replacement power cost related to four forced outages the Division views as imprudent. This amount is 186,000 less than recommended in the Division's direct testimony due to the removal of the October 11th, 2023, Naughton 2 outage.

A 19.4 million adjustment to remove the state-specific costs to comply with the Washington Climate Commitment Act known as Washington CCA.

A 4.8 million adjustment to remove the Electric Schedule 137 costs for deferral years 2020 through 2022. These costs were known to the Company but not included in the Company's EBA recovery requests for those deferral years.

A $72.3 million adjustment to more accurately allocate trading activities occurring in PAC West. Market purchases, including hedging transactions occurring in PAC West, do not appear to benefit Utah customers in proportion to the costs currently allocated to them.

The Division's recommended 72.3 million PAC West adjustment is 57.5 million less than the amount the Division recommended in direct testimony.

The Division's witnesses from Daymark, Mr. Phil DiDomenico and Dan Koehler, will testify regarding Daymark's EBA review and will address its recommended adjustments for outages and the removal of the Washington CCA compliance cost.

This concludes my summary.

CHAIR FENN: Okay. Thank you very much. I appreciate that.

Anything, Mr. Grecu, before we turn him over for cross-examination?

MR. GRECU: Nothing further from me.

CHAIR FENN: Okay. All right. Let's see. Mr. Moscon, are you conducting the cross-examination here?

MR. MOSCON: I am. Thank you, Chair.

CHAIR FENN: Thank you.

CROSS-EXAMINATION

BY MR. MOSCON:

Q. Good afternoon, Mr. Smith.

A. Good afternoon.

Q. I think we can really condense the questioning that I was going to have for you because there's been so much exploration of some of these topics already. Do you have a copy of all of your testimony there in front of you?

A. I do, yeah.

Q. I want to just clarify a couple of points that you made, and then I'll pass the mic to others.

If I could have you turn to Exhibit 1.2 to your direct testimony, which is the audit report, and go to page 20. While you're going there, I'm going to just note for everyone that this is the confidential audit report, not the public summary. I do not believe anything that I'm going to ask you about is confidential.

A. Okay.

Q. It's just the specific things I was looking for not in the public summary.

A. Right.

Q. But I don't foresee a need to go into confidential session. So there's no alarm taken by the yellow paper.

A. Which page did you say?

Q. Page 20 of 1.2. And I'm looking at the very bottom of the page. There's the bottom paragraph that's introducing DPU Chart 1, and in the bottom paragraph, you note -- and just in case they're confidential -- I don't know -- I won't use the exact numbers -- but you note that in 2023 that the -- that there was a significant decrease in coal fuel expense; correct?

A. That is correct.

Q. And then if you turn the page and go with me to page 21 -- and I'm looking at the paragraph at the bottom of this page, after Mr. Painter's explanation of your point, and you have a sentence there that starts, "The results." Do you see that?

A. Yeah.

Q. And I'm just going to read it. "The results of the Company's adjusted coal contracts, deliveries, and depressed generation in 2023 contributed significantly to the Company's requested large EBA deferral period."

Do you see that?

A. Yes.

Q. Okay. And you agree with me that one -- it's not the only -- but one of the main drivers for the large deferral on the topic that has just been the subject of questioning for Mr. Wilding was that, in fact, because of coal contract issues that that was a driver that was increasing the Company's need to purchase additional power trade; is that correct?

A. The decreased generation of coal -- the Company actually suppressed the price so that it wouldn't generate coal as much, and so, yeah, they did result in either gas or market purchases -- I want to say market purchases.

Q. In fact, I think your next sentence is really what I was driving at.

A. Okay.

Q. It states, "The Company explained that the reduction in coal generation was predominantly due to coal supply issues in Utah, including force majeure events."

Do you see that?

A. Yes.

Q. And it's true, isn't it, that nothing that the DPU has filed with the Commission in this docket calls into question that, in fact, that there were fires and floods that did impact the Company's coal supply for 2023; is that correct?

A. That's correct.

Q. Okay. Now, if you would turn with me to your corrected rebuttal testimony, and I'm going to be going to page 8.

A. I'm there.

Q. Okay. And in the -- below Table 2, there's a question and answer there that talks about this adjustment that you referenced in your summary that your answer starts on line 145. Do you see that?

A. Yes.

Q. Okay. Now, I think you noted that your rebuttal testimony has a different number. It's a revision based on the -- or excuse me -- based on the DPU's initial filing in your direct testimony; correct?

A. That is correct.

Q. And in your corrected rebuttal testimony, you now recommend that instead of a total reduction for the west side market purchases, but a reduction of the purchase and hedging cost from the 44 percent, which would be the Utah-allocated share to 20 percent; correct?

A. That is correct.

Q. And in your testimony, you indicate that where you derive this 20 percent figure is because that's the number that Mr. Trevor Jones used in the general rate case testimony, and you reference the Docket 24-035-04; is that correct?

A. Correct.

Q. Would you agree with me that you, yourself, have not done any analysis independent of Mr. Jones to come up with how or why that 20 percent figure is correct?

A. I wouldn't fully agree with that. I will say that Trevor probably acted as a lead on this topic. However, analysis being obviously it would be something less than 44 percent. So -- and so in the absence of specific details on some of the allocation details that we could have used, we came up with a 20 percent figure.

Q. Okay. Well, to the extent you refer to Mr. Jones' testimony here in your testimony, you agree with me, don't you, that Mr. Jones, when he came up with this figure in his testimony in the general rate case, indicated that this wasn't precise? It could be a range. It could be 10 percent. It could be 15 percent. It could be 20 percent. That's correct, isn't it?

A. Yeah. Currently the Company, as well as other parties in PacifiCorp, have spent a lot of time looking at allocations and to the point where discussions within the multistate process had to be discontinued. And so that's sort of an ongoing issue. You know, the 2020 Protocol is now five years old. So allocation issues -- it is something that more than the DPU, I believe, is concerned over.

Q. Okay. And I appreciate that, but that's not really my question. Let me ask it this way.

Would you agree with me that in this docket that the Division has not done an analysis that would identify quantifiable evidence that would indicate -- of all of the market purchases that it is trying to pull back out of the deferral, that it can show demonstrably how a reduction of 24 percent is appropriate, leaving 20 percent to the Company?

A. Given that 90 percent of the transactions occur -- and I know that there are issues with that that Mr. Wilding addressed -- and that the Company is operating as holistically -- however, given that some of the transmission can't transfer east, west, so forth, and state policies which have been sort of underlying some of these changes going forward -- may not allow some things to happen that other states might have approved -- the analysis is just that it's somewhere between probably 10 and 44 percent.

Q. Okay. So the Division's best testimony is it doesn't have a precise number. It's somewhere between 10 percent and 44 percent that the Company should be able to recover in this docket?

A. We are suggesting a recommended 20 percent adjustment.

Q. I understand that that's the recommendation, but you agree with me that that's not based on any quantifiable data. That's merely a recommendation; is that correct?

A. It's a recommendation.

Q. I think that's it. Thank you very much.

A. Thank you.

CHAIR FENN: Okay. Does anybody else have cross-examination?

Okay. All right. We'll turn to Commissioner Harvey.

EXAMINATION

BY COMMISSIONER HARVEY:

Q. Talking about the trades, front office transactions that the DPU has recommended the Commission remove from the EBA, I'm trying to get a little bit better sense of what the DPU thinks the Company should have done differently than it did when it made those trades. If you could talk for a minute or two about that, and then I'll probably have some follow-ups depending on how you enlighten me.

A. Okay. It depends on how far back, I guess, you want to go. I did mention in my rebuttal that the Division voiced concerns over the Company's non-procurement of other resources that would enable them to be less dependent on the market. So that would be, like, a peaking gas plant is what we suggested. Also batteries as has been discussed. That would be another one. But -- so given that we're dealing with what we have -- if you could just ask your question one more time, and I'll answer it better.

Q. Well, we're being -- the Division is asking the Commission to disallow a significant percentage of these trades or the costs of those trades. The Company's testimony, as you just heard and as you've read in written testimony, that the Company says these are necessary to meet load, and I'm just curious what the DPU thinks the Company should have done differently. And you can answer that in two parts; right? You can say differently given what we have now or differently long term, but I'd like to hear one or the other or both.

A. Okay. So long term we'd like to see them move away from the market as much as they can. In other words, providing their own generation in those peak hours, and, again, buy batteries or some kind of gas peaker.

I do realize that some states don't allow some of that to occur within their state, and they may not even allow it to be within the PacifiCorp system, given what their state protocols might entail, but as far as -- I mean, obviously, they had to meet their -- their load, and nobody wants the power to go out, but the fact that they're -- that the product that they're buying -- it's not clear as the only product available to them.

Although, you know, we haven't seen an analysis of, "Hey, we could have gone with product B. It might be a little more costly, but it would narrow down that scope of the time those trades might be needed." Instead, they're buying that big block of time. And so I guess, looking at it now, we -- going forward or even looking back, it would be nice to have some kind of an analysis that would allow us to do kind of what I think you're alluding to -- is, like, what could have been done differently? What other options do we have?

And the answer is I -- I don't know that they could have done much different than they did, given where they're at. However, we don't know that -- it's not been made obvious or apparent to us or brought forward to us in a way that we could really say that there isn't a better option out there or -- or, you know, looking long-term, of course, is always better and what their real long term -- I mean, they talk about procurement of resources, but those are wind and other things that don't meet the peak load, other than the mentioned batteries today.

I don't know if that answers your question.

Q. So I would characterize your answer as saying the Division expressed concern in the past that sufficiently -- that a sufficient amount of dispatchable resources were not being built, and as a result, they think the Company's current actions are imprudent. Is that a fair summary?

A. Given that they didn't take the resource thoughts and other choices, yes, I would agree with you, that it's imprudent because they didn't make the choices necessary to get themselves out of the situation they find themselves today.

Q. I'm asking is it a fair summary of the Division's position?

A. Correct.

Q. Okay.

A. Yep.

Q. And I apologize in advance, but are you the witness that dealt with the Schedule 137 --

A. Yes.

Q. -- adjustment?

A. Yes.

Q. Okay. I thought you were, but I wasn't positive.

In your mind -- well, let me rephrase that. I'm sorry.

Would you explain to me your -- what distinction you see between the types of adjustments that were cited in the Company's testimony as being allowed after the fact as compared to this particular adjustment?

A. So there were a range of -- of things mentioned. Those include things like just the annual true-up, which, of course, you have to have, and it does span an amount of time. And also other things that don't fully close within, you know, the given calendar year.

That was another one. Specifically -- it was mentioned -- a meter failure that happened in 2021 that caused the Company to file a submittal of an update to -- to their -- the supplemental testimony to their initial filing. So what happened in that case, the Company filed in March. In June they filed a supplemental testimony advising that there was a meter failure. So it was a physical failure of equipment that necessitated them to recalculate the allocation, which was the transmission line between Utah and Idaho.

And so when they did that, they found that Utah was actually not given enough load compared to what Idaho should have gotten and so -- therefore -- so -- and that went into settlement hearings. So the

Commission really didn't have a chance to -- to weigh in on that particular issue.

So -- but the difference between that one is it was not known until somewhere between March and June, as far as we've been told, that the meter failure was not known. And so that's the difference. It has to do a lot with when this -- the cost was known and how was it dealt with; right?

So in -- in this case with the Schedule 137, they had -- the Company had the opportunity to include it in their filings for -- for years '20 through 2022. So it's three years of EBA filings they could have recouped those costs. And as the Company is aware, we did not challenge the '23.

So -- so the real difference is when was the cost known and -- and why wasn't it included; right? If it's just an oversight, is it -- we -- the Division didn't feel prudent to just reopen a case to recoup costs that the Company just didn't recover. And, in fact, we did say that, you know, if this is the case, then would they be willing to have it open to other people coming with other adjustments later -- other years later that we just didn't see or -- you know.

So -- so that's really the difference -- is the known and knowable and what -- what caused it to not be included in those other years.

Q. Okay. To follow up on the what caused it, just a clarification there. Is it the DPU's position that in all of the examples provided by the Company in their testimony, it was caused by things that were not Company errors?

A. Correct.

Q. That in -- I'm sorry.

A. Oh, no. I was just agreeing with you.

Q. We're in the hallway.

A. Right.

Q. But that in this particular case the DPU's position is that it's clearly a Company error, not an external or not an unknowable thing?

A. Correct, yes.

Q. Okay. And then for the Washington CCA or -- is that being talked by Mr. DiDomenico?

A. Yep.

Q. Okay. I think that's all my questions. Thank you.

CHAIR FENN: Commissioner Clark?

THE WITNESS: Thank you.

COMMISSIONER CLARK: I don't have any questions. Thank you.

EXAMINATION

BY CHAIR FENN:

Q. Mr. Smith, just one question referring back to Mr. Painter's testimony about the Schedule 137 costs. In his surrebuttal he indicated that the Commission had allowed costs outside of the typical period to be recovered in a case that was due to an error. Are you familiar with that testimony?

A. I am.

Q. Okay. Can you differentiate -- is there a differentiation between what Mr. Painter's position is and what your position is?

A. Yes.

Q. Please explain.

A. It's the -- the scenario I just mentioned where there was a meter failure between the transmission line.

Q. Okay. It's that scenario?

A. It's that one.

Q. Okay.

A. I don't know why it was termed an error at that point other than it was an error of the meter. It was a meter error. It wasn't a clerical error as far as I could tell -- what was presented to us at the time, both in, you know, DRs and what have you. So -- so I don't know why it was termed an error, because as we understood it, it was just a -- they caught that the meter wasn't recording the information correctly. So I guess the error was in the meter.

Q. So it is your position that the -- if the costs are known and knowable, they should be included within the one-year EBA period and those costs were not known and knowable. Is that --

A. The 137 costs -- oh, no. The meter --

Q. Meter cost.

A. -- failure was not known until between that filing in March of 2021 to June of '21. So somewhere in that, it became knowable to the Company, is what we've been told. And, therefore, that caused a supplemental filing, which, you know, resulted in a settlement -- is what it did. It never went to the Commission to -- to review.

Q. Okay. Is there any other differentiation you can draw between that example that was used to say you've already done this once before in this type of scenario and you should do it here for these Schedule 137 costs?

A. Well, one thing is, you know, to have this be sort of equal, the Company wants -- it knew about it between March and June of 2021. To make it equal to what we're talking about, then the Company would have waited three years and then filed something about it.

Q. Yeah.

A. So, yes, it is. It's all in the details, mostly the known and knowable and what was the result. I mean, the Company has all access to -- to data, to information, and I don't think customers should be impacted by the results of a Company error like this when it could have been just dealt with at the time rather than --

Q. And -- and from your investigation of this, what have you been told as to why it wasn't included in the prior EBA?

A. It just was not -- I believe it was just a mistake -- is how I understood it.

CHAIR FENN: Okay. I have no further questions.

All right. We'll excuse you, Mr. Smith. Thank you for your --

THE WITNESS: Thank you.

CHAIR FENN: -- testimony today.

Your next witness?

MS. SCHMID: The Division would like to call Mr. Dan F. Koehler as its next witness. May he please be sworn.

CHAIR FENN: Sure. Mr. Koehler, pronounced like "Taylor."

THE WITNESS: That's right. Years of training.

CHAIR FENN: Yep. I remember that from the first case. Mr. Koehler, will you raise your right arm.

DAN F. KOEHLER

was called as a witness, and having been first duly sworn to tell the truth, testified as follows:

CHAIR FENN: Thank you very much. You may be seated.

DIRECT EXAMINATION

BY MS. SCHMID:

Q. Good afternoon.

A. Good afternoon.

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

A. Sure. My name is Dan F. Koehler, D-a-n, F as in "Fulton", K-o-e-h-l-e-r.

Q. What is your business address?

A. My business address is 370 Main Street, Suite 325, in Worcester, Massachusetts.

Q. By whom are you employed?

A. I am with Daymark Energy Advisors.

Q. And what is your title?

A. And I am vice president and principal consultant.

Q. Could you please tell us just a little bit about Daymark?

A. Sure. Daymark is a consultancy providing regulatory, economic, management, and investment advisory services to the natural gas and electric power industry across North America. Our expertise and experience are interdisciplinary and include transmission planning and market analytics, clean energy policy, competitive procurement, and portfolio structuring. Also market design, regulatory economics, and utility tariffs and rate design.

Q. Thank you. Could you please tell us on whose behalf Daymark is participating in this docket.

A. The Division.

Q. Could you please tell us in just a few words what the Division hired Daymark to do.

A. Sure. We had -- we had several tasks in this proceeding. Our first task was to review and assess actual planned outages to ensure that these outages and the cost impacts are appropriate. We also reviewed a sample of several dozen of the tens of thousands of power and natural gas transactions settled by the Company in 2023 for accuracy and prudence. We reviewed certain specific issues related to key drivers of EBA costs. We reviewed variances in production tax credits, or PTC, offsets to EBA costs. We reviewed the allocation of costs to Utah customers associated with the Washington CCA filing. We were asked to review PacifiCorp's compliance with risk management and corporate governance policies.

Q. We just mentioned that you had testified in front of the PSC before in Rocky Mountain Power's last general rate case, Phase I. When did you, as part of Daymark, begin analyzing the EBA on behalf of the Division?

A. Oh, jeez. First gotcha question.

Q. Was it perhaps --

A. It was -- well, I've been working on it since the first one -- what was that -- 10 -- 2010?

Q. It was an '11 docket.

A. '11. Okay. An '11 docket. And I've been a witness since a '15 docket, I believe.

Q. Perfect. I'll now turn to the testimony, exhibits, and reports that Daymark filed in this docket. They were prepared and filed by you and Mr. DiDomenico on behalf of Daymark for the Division. Did you and Mr. DiDomenico jointly prepare and cause to be filed what's been marked for filing as DPU Exhibit Number 2.0

Dir, the direct testimony of Philip DiDomenico and Dan F. Koehler in redacted and confidential form, along with exhibits and work papers for the DPU that was filed on November 5th, 2024?

A. Yes.

Q. Did you also prepare and cause to be filed DPU Exhibit Number 2.0 R, the rebuttal testimony of Philip DiDomenico and Dan F. Koehler in redacted and confidential form along with the exhibits on -- on January 7th, 2025?

A. Yes.

Q. Did you and Mr. DiDomenico prepare and file any surrebuttal testimony on behalf of the Division?

A. No.

Q. Have you and Mr. DiDomenico discussed whether there are any changes or corrections that need to be made to the direct and rebuttal that you filed?

A. We have discussed it, and there are none.

Q. If asked today -- you were asked to prepare and file the testimonies and exhibits described above, would the contents be the same as those contained in your filed testimonies and exhibits?

A. Yes.

Q. Do you adopt the testimonies and exhibits as described above as part of your testimony here today?

A. I do.

MS. SCHMID: The Division would like to move for the admission of 2.0 Direct and its exhibit and 2 point R -- 2.0 R and its exhibits.

CHAIR FENN: Without objection, we'll admit the direct and rebuttal testimony and the exhibits of Mr. Koehler and Mr. DiDomenico.

(Philip DiDomenico and Dan Koehler's prefiled testimony and exhibits were admitted into evidence.)

THE WITNESS: DiDomenico, yes.

CHAIR FENN: DiDomenico. Can I just ask the question -- is he going to be testifying also in this proceeding, or are you going to be testifying and not him?

THE WITNESS: So I'm prepared to speak to all issues in our -- in our materials with the exception of prudence of outages. If there's any questions related to the prudence of outages, those should be addressed to Mr. DiDomenico.

CHAIR FENN: Okay. All right. Glad to get that straight. Okay.

Q. (BY MS. SCHMID) Have you had a chance to prepare a summary for the Commission?

A. I have.

Q. Does that summary contain information that you believe the Company has marked confidential?

A. It does.

MS. SCHMID: With that, the Division would like to move or request that this hearing be moved into closed session because Mr. Koehler's summary contains and discusses confidential information, and getting this information on the record is in the public interest.

CHAIR FENN: Okay. That's very good. Let's -- let's -- let's do this, I think, the right way. I think we need a motion of one of the Commissioners to do that.

COMMISSIONER CLARK: Yeah. I'll move that we close the session.

CHAIR FENN: Okay. Commissioner Harvey gives us the thumbs up, and so we'll go into the closed session. Thank you, Ms. Schmid.

Let's now just reiterate, if there's anyone here who has not signed a confidentiality agreement, is not subject to the terms thereof -- I'll let y'all folks look around. If you see anybody you're worried about, please let us know, but, otherwise, we know that folks on the phone are -- already have been cleared. Anybody else that we have any concerns about?

Okay. We're going to continue in closed

session until further notice. Go ahead.

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(THE FOLLOWING PORTION OF TRANSCRIPT PAGES 196-223 HAVE BEEN MARKED CONFIDENTIAL.)

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CHAIR FENN: So we're going to go back into public session now, and if we need to go back into confidential, we'll -- somebody will tell us.

Mr. Moore, we're going to turn to you for your witness.

MR. MOORE: Thank you. The Office of Consumer Services calls Philip Hayet and ask that he be sworn.

CHAIR FENN: Okay. Mr. Hayet, let's see if we can get you -- oh, your video is already up. Can we get him on the -- the main screen? Why don't -- all right. We're going to get you there. All right.

Mr. Hayet, would you raise your right arm, please.

PHILIP HAYET

was called as a witness, and having been first duly sworn to tell the truth, testified as follows:

CHAIR FENN: We can't hear you. We saw that you said, "I do." So we won't make you repeat that, but your -- your microphone is not turned on.

THE WITNESS: I do. My apologies.

CHAIR FENN: Okay. All right. We gotcha. We'll turn to Mr. Moore now.

DIRECT EXAMINATION

BY MR. MOORE:

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

A. My name is Philip Hayet, P-h-i-l-i-p and H-a-y-e-t.

Q. What is your business address, and how are you employed?

A. My address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. For who --

A. And would you repeat the second part?

Q. How are you employed?

A. I'm a consultant on behalf of -- I work for Kennedy and Associates, and I'm a consultant for the Office.

Q. On January 16th -- no.

On December 6th, 2024, did you file direct testimony on behalf of the Office in this docket?

A. Yes, I did.

Q. On January 16th, 2025, did you file surrebuttal testimony?

A. Yes, I did.

Q. Do you have any changes that you'd like to make to this testimony at this time?

A. I have one change I'd like to make at line 198 of direct testimony. The number that's in that line 2039 should be 2029, and that's the only change I have.

Q. Other than that change, if I asked you the same questions that are in your written testimony today, would your answers be the same?

A. They would.

MR. MOORE: Commission, there was a -- the OCS initially failed to include his resume with his direct testimony, and he references his resume in his testimony. So I would like to admit the resume today as OCS Exhibit 1.1 D. I had discussion with the parties and presented them with the resume, but I'd like to provide one to the court reporter and to the Commission, if you'd --

CHAIR FENN: Sure. We'd like to have that. All right. Are you moving the admission of this?

MR. MOORE: I am.

CHAIR FENN: Okay. While you're distributing that, without objection, we will move to admit the direct testimony and surrebuttal testimony of Mr. Hayet with the one correction on line 198 of his direct testimony, and we'll also admit as OCS 1.1 D Mr. Hayet's resume.

(Philip Hayet's prefiled testimony and OCS Exhibit 1.1 D were admitted into evidence.)

CHAIR FENN: Mr. Hayet, anytime it's more than

16 pages long, it's too many pages for me to read. This is 17 pages long. That's pretty -- that's an extensive resume.

MR. MOORE: Mr. Hayet --

THE WITNESS: (inaudible).

(Reporter clarification.)

THE WITNESS: I said it has all my appearances on it. That's why it's long.

CHAIR FENN: Okay. Well, thank you for it. I was just being obviously facetious.

THE WITNESS: I know.

CHAIR FENN: I apologize for my attempt at levity.

THE WITNESS: Appreciate it.

Q. (BY MR. MOORE) Mr. Hayet, have you prepared a testimony of your testimony?

A. Yes, I have.

Q. Please proceed.

A. Good afternoon, Commissioners. In my direct and rebuttal testimony, I address three issues that the DPU also addressed.

The first issue concerned the prior period adjustment for Schedule 137 costs in which Rocky Mountain Power is seeking to recover costs that were known and knowable multiple EBA deferral periods before this one because the Company simply overlooked the inclusion of those costs in the proper EBA period. Rocky Mountain Power has long incurred costs related to export credits first with Schedule 136 and then beginning in 2020 associated with Schedule 137. Schedule 137 was a known and knowable matter at the time the costs were incurred.

RMP has taken different positions on related issues at different times. In the last EBA proceeding regarding calendar year 2022 deferral costs, the Company argued against affording stakeholders the opportunity to present adjustments in a future EBA related to the previous EBA deferral period. The Company stated the parties should only be able to propose adjustments that are related to the calendar year deferral period and not prior period. In this proceeding, the Company has pointed out that out-of-period adjustments are not prohibited and are common.

OCS agrees that out-of-period adjustments have been permitted. However, the example the Company gave relates to cases in which the Company knew about the specific matters at the time of the deferral period; however, the final determination of the costs were not known until a later time. In this -- in this case Schedule 137 and associated costs were known at the time of the deferral period; however, the Company neglected to include them at the time and instead is seeking to recover them in this later deferral period.

OCS recommends removal of 4.8 million, including interest, in Schedule 137 costs incurred -- incurred in the years prior to the '23 deferral year.

The second issue relates to the state of Washington Climate Commitment Act, or CCA, in which the Company is seeking to recover costs incurred in Washington. PacifiCorp itself recognizes these costs are discriminatory because Utah customers are charged higher costs than Washington customers and the subsidized programs that only benefits Washington customers. The CCA requires the Company to purchase allowances to cover greenhouse gas emissions related to fossil fuel fire generation, such as PacifiCorp's Chehalis natural gas plant.

PacifiCorp was obligated to spend 42 million by the state of Washington to buy allowances, and the state of Washington then allocated free allowances back to PacifiCorp associated with Washington state retail customer load alone. In essence, Washington state customers paid less for Chehalis energy compared to all other PacifiCorp customers.

PacifiCorp has taken the position in this proceeding that the Chehalis cost is like a generation tax that occurs in other jurisdictions for other generation and it's fair that Utah customers should have to pay the costs. However, there is a distinction in that in the case of a generation tax, there is no corresponding distribution of revenues back to the utility customers of the state that charges the taxes like there is with the CCA revenue.

Interestingly, Rocky Mountain Power itself has taken action opposing the allocation benefit to just Washington state customers in its suit it filed against the Washington State Department of Ecology in the US District Court for the Western Division of Washington. In that suit PacifiCorp argues that the cost is discriminatory, and PacifiCorp stated the costs harm -- harm PacifiCorp's non-Washington customers.

Furthermore, three other states -- including Idaho, Wyoming, and Oregon -- have all disallowed this discriminatory costs from being recovered. The Oregon Public Service Commission, for example, does not justify -- apologies -- the Oregon Public Service Commission, for example, recognized PacifiCorp is faced with conflicting instructions from states. However, it noted that that does not justify Oregon retail customers having to pay the discriminatory costs.

OCS continues to recommend the disallowance of 19.4 million, including interest, on a Utah jurisdictional basis for the '23 deferral year.

The third issue relates to a concern the DPU's raised in that net power costs and the deferral balance has gone significantly overtime corresponding to PacifiCorp's reliance on power purchases. This issue ties together concerns about costs customers have to pay through the EBA and the fact that there is a lack of incentive, as has existed in the past, for the Company to properly plan to ensure that risks the customers are exposed to through the EBA are minimized.

Today, there is no longer a suring mechanism that aligns ratepayer and PacifiCorp's interests in minimizing net power costs. When net power costs increase, PacifiCorp simply flows through those costs to customers --

(Witness's screen freezes. Discussion held off record.)

A. All right. Today, there is no longer a suring mechanism that aligns ratepayer and PacifiCorp's interests in minimizing net power costs. When net power costs increase, PacifiCorp simply flows through those costs to customers.

In my testimony, I outlined some planning inadequacy that have arisen, including a canceled RFP, lack of acknowledgement of an IRP because the Company ruled out adding GAAP resources, the MFP process that was terminated, and the fact that for years PacifiCorp has only -- has overly relied on front office transactions, also referred to as market purchases. By relying on market purchases, the Company has, in essence, exposed customers to unhedged market energy purchase costs that are recovered through the EBA.

Given the planning deficiencies mentioned, the OCS is concerned by the risk and the costs customers are being forced to bear entirely, and the OCS recommends that the Public Service Commission open a new docket to address whether or not the EBA mechanism is appropriately acting as a risk sharing mechanism or if it is acting as a backstop to PacifiCorp's planning processes. This docket should investigate more thoroughly the reasons net power costs and deferral costs have increased so dramatically, market purchases have increased significantly, planning deficiencies have occurred, and also how the EBA should be changed such that customers would have greater protections than currently exist.

And that concludes my summary.

CHAIR FENN: Okay. Thank you for your

summary, Mr. Hayet.

MR. MOORE: Mr. Hayet is now available for cross and questions from the Commission.

CHAIR FENN: Okay. Mr. Kumar?

MR. KUMAR: I think I have just a -- very quick few questions based on Mr. Hayet's summary.

CROSS-EXAMINATION

BY MR. KUMAR:

Q. Mr. Hayet, can you hear me?

A. Yes, I can.

Q. Mr. Hayet, in your summary you cite to the OCS's recommendation from last year's energy balancing account proceeding where the OCS recommended that -- I believe where the OCS recommended that the review of the prudence of certain dispatch costs related to coal facilities be delayed; is that correct?

A. Yes.

Q. And in that proceeding, the costs associated with those coal facilities was actually included in that proceeding; correct?

A. Yes.

Q. And so the OCS was requesting, essentially, a delay of the prudence review of costs that had been included for review in that proceeding; correct?

A. It was requesting delay for information that was going to be provided in a report in another state.

Q. But it was requesting a delay of the prudence review of those costs that had been included; correct?

A. Yep.

Q. Okay. I have no further questions. That's it.

CHAIR FENN: Okay. Thank you, Mr. Kumar. I assume no one else has questions. I'll turn to Commissioner Harvey.

COMMISSIONER HARVEY: Just a few to make sure that I'm clear on the OCS's position here.

EXAMINATION

BY COMMISSIONER HARVEY:

Q. With respect to the Schedule 137 costs, your distinction between this -- the inclusion of this versus the ones that were cited in other testimony is because you -- you explained because of Company error involved versus with the others it was an inability to know the actuals. Would you say that's correct?

A. They -- they should have -- my position is they should have known and included -- so the information about the issue was known, the costs were known; and, therefore, that -- those costs could have been included but for the error that occurred.

In the other cases it was waiting on

information to be determined, and it wasn't known and knowable at the time. For example, there was a case in which liquidated damages -- there was a fight that was going on, a litigation that was going on, and the results were not known at the time. The ultimate costs were not known at the time of the -- of the deferral period.

Q. Thank you. With respect to your recommendation regarding the EBA, you mentioned in the summary that you don't believe the Company's incentives are aligned with consumers' incentives. What are potential mechanisms that would align those incentives in your mind?

A. Well, in the past there was a sharing mechanism, and that sharing mechanism meant that when there was a certain amount of under-recovery or over-recovery, there was a sharing between the customers and the Company. That led to -- the Company recognized that it wasn't going to fully recover the costs through the EBA because of the sharing proportion. Then it had to, you know, work harder to minimize any deficiencies that occurred, and that might mean perhaps that it had to conduct more frequent rate cases so that -- that -- you know, because they keep citing to this issue that, you know, the rate case hasn't happened in so long of a period, and, therefore, the difference between the base amount and the actual 2023 cost is so significant now.

So that would be one issue. The Company would be more aligned with trying to ensure that the -- that the -- the balance -- the deficiency didn't grow as significant as it has. The fact that we no longer have the sharing mechanism means that we no longer have the incentives aligned.

So I think that through an investigation, we could work on ways to ensure that the Company is working harder to ensure that the net power cost balance and the under-recovered balance isn't as significant as it is today.

Q. As a follow-up on the incentives, would you say that the Company has received significant pushback, both from political actors as well as from the general public and certainly from the testimony in this -- this docket, regarding the size of the -- the overage, I guess I should say?

A. Yes. Just like any utility, I think that they hear a lot of comments from the public when they -- when net power costs go up and rates increase. I think that parties have let them know that through the testimony.

But I think that through a proceeding such as what I'm suggesting, a lot of issues that -- that drive the net power costs could be investigated. You know, there's this whole question about the market purchases and the size -- the growth in the market purchases and how that correlates to the growth in net power costs and the under-recovery that occurred, you know.

And there are other issues that could be examined in addition, such as, you know, the Company, in its IRP, they didn't even examine the use of gas resources as potential resources that could be -- could be added to their system a few years back, and that was a -- that led to the potential lack of having dispatchable capacity in -- maybe not in 2023, but, certainly, you know, prior to 2030. On a going forward basis, there could be a significant need for dispatchable capacity as more and more intermittent resources are being added to the system. And, yes, I know that these are also IRP-related issues; however, they drive to the EBA. They drive to the net power costs that are recovered through the EBA.

So I think there's a whole large question of are the right incentives being in place such that the Company doesn't just simply wind up in a situation where net power costs are going to go up, no sharing mechanism exists, and the Company simply recognizes it's entitled to recover any additional costs through the EBA?

Q. Thank you. That's all my questions.

CHAIR FENN: Commissioner Clark?

COMMISSIONER CLARK: I don't have any questions. Thank you.

CHAIR FENN: Mr. Hayet, I don't have any questions either. We will excuse you. Thank you for participating.

THE WITNESS: Okay.

CHAIR FENN: We appreciate it.

MR. MOORE: Nothing else from the OCS. Thank you.

CHAIR FENN: Okay. All right. We have Mr. Higgins is the -- I believe he's our last witness; is that correct?

MR. RUSSELL: I think so. Utah Association of Energy Users calls Kevin Higgins.

CHAIR FENN: Okay. Welcome again, Mr. Higgins. Will you raise your right arm.

KEVIN C. HIGGINS

was called as a witness, and having been first duly sworn to tell the truth, testified as follows:

CHAIR FENN: Thank you, Mr. Higgins. Please be seated.

DIRECT EXAMINATION

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BY MR. RUSSELL:
Q. Good afternoon. Could you state and spell your name for the record, please.
A. My name is Kevin C. Higgins, K-e-v-i-n, middle initial C., H-i-g-g-i-n-s.
Q. And can you tell us who you work for and in what capacity.
A. I'm a principal in the consulting firm Energy Strategies.
Q. On whose behalf do you offer testimony in this proceeding?
A. I'm here on behalf of the Utah Association of Energy Users, or UAE.
Q. And in that capacity did you file or cause to be filed direct and surrebuttal testimony in this proceeding?
A. Yes, I did.
Q. And that's -- direct testimony was filed on December 6th along with UAE Exhibits 1.1 through 1.4 and surrebuttal testimony on January 16th of 2025; is that right?
A. Yes.
Q. And with respect to that prefiled testimony, do you have any corrections to make?
A. No.

Q. If asked the same questions today that were posed in your prefiled testimony, would you provide the same answers?

A. Yes, I would.

MR. RUSSELL: I'll move for the admission of Mr. Higgins prefiled testimony and exhibits.

CHAIR FENN: Seeing no objection, we'll -- the Commission will admit the prefiled direct and surrebuttal testimony of Mr. Higgins and the accompanying exhibits.

(Kevin C. Higgins' prefiled testimony and exhibits were admitted into evidence.)

Q. (BY MR. RUSSELL) Have you prepared a summary of your testimony for us today, Mr. Higgins?

A. Yes, I have.

Q. All right. Please proceed with that.

A. Good afternoon, Chairman Fenn, Commissioner Clark, Commissioner Harvey.

In my testimony I address two different topics. First, I recommend that costs associated with the state of Washington's Climate Commitment Act, or CCA, should be disallowed from the recovery of the calendar year 2023 EBA deferral. The CCA should be viewed as a Washington state policy action that should not implicate Utah rates. I support the recommendation of the Division of Public Utilities that the $42.1 million of total Company amount spent on Washington CCA allowances be situs assigned to Washington and removed from the Utah-allocated net power costs.

Second, in my direct testimony I identified certain anomalies in the allocation of EBA-related costs to Schedules 9, 31, and 32 that resulted in an over-assignment of costs to Schedule 9 for recovery through the EBA. Accordingly, I made a number of recommendations to remedy this problem.

In his rebuttal testimony, Rocky Mountain Power witness Mr. Meredith acknowledged the concerns I raised and proposes a resolution to the problem that I believe is well reasoned and fair to all customers. Therefore, I recommend adoption of the Company's revised allocation approach as detailed in Mr. Meredith's rebuttal testimony and further supported in his rebuttal exhibits.

I also agree with Mr. Meredith's proposal to rectify the overallocation of calendar year 2023 EBA deferral costs to Schedule 9 through an adjustment to the calendar year 2024 EBA deferral recovery, which comports with the recommendation I made in my direct testimony.

That concludes my summary.

CHAIR FENN: Okay. Thank you, Mr. Higgins.

MR. RUSSELL: No additional questions for Mr. Higgins. He's available for cross-examination and Commission questions.

CHAIR FENN: Okay. We'll turn to Rocky Mountain Power.

MR. KUMAR: We have no questions for this witness.

CHAIR FENN: Okay. Does the Division or the Office have any questions?

Okay. I'd turn to Commissioner Harvey and see if he has any questions of Mr. Higgins.

COMMISSIONER HARVEY: I'm going to ruin my record. I have no questions.

CHAIR FENN: Okay. Commissioner Clark?

COMMISSIONER CLARK: No questions. Thank you.

CHAIR FENN: Well, I guess I'll have no questions as well. That's great.

Well, that was succinct, and we appreciate it. Thank you, Mr. Higgins.

THE WITNESS: Thank you.

CHAIR FENN: We'll excuse you.

I believe that concludes the testimony on the EBA; is that correct? Is there anything that we need to take up before we adjourn from any of the parties?

All right. We -- I don't recall when -- we have a 300-day period -- I believe it is. Is that what it is to issue an order in this -- in an EBA proceeding? Can somebody clue me in on that?

MR. KUMAR: I believe so, but I haven't looked at the statute.

UNIDENTIFIED SPEAKER: It's 300 days.

CHAIR FENN: 300 days? Okay. All right. Does anybody know when that 300 days runs? I understood it was sometime in February. Do you know?

MS. PASCHAL: February 25th.

CHAIR FENN: February 25th. Melissa knew. I should have just asked Melissa. Would have had the answer. Okay. Well, we'll issue an order before February 25th. That will be something that we'll get on.

And seeing no other questions or comments -- boy, who would have thought we would be out of here before 4:30? All right. We'll adjourn this proceeding. Thank you so much for your attendance and participation.

(This hearing was concluded at 4:27 p.m. MT.)

* * * * *

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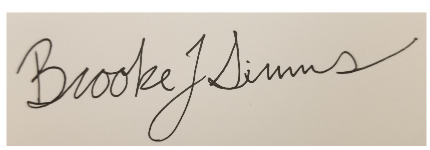
STATE OF UTAH)
)
COUNTY OF UTAH)

I, BROOKE SIMMS, an Idaho Certified Shorthand Reporter, Utah State Certified Court Reporter, and Registered Professional Reporter, hereby certify:

THAT the foregoing proceedings were taken before me at the time and place set forth in the caption hereof; that the proceedings were taken down by me in shorthand and thereafter my notes were transcribed through computer-aided transcription; and the foregoing transcript constitutes a full, true, and accurate record of such oral proceedings had, and of the whole thereof.

I further certify that I am not a relative or employee of an attorney or party, nor am I financially interested in the action.

I have subscribed my name on this 18th day of February, 2025.



Brooke Simms, RPR, CCR, CSR
Idaho CSR No. 1174
Utah CCR No. 12335391-780

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[addition - allocate]

[chair - chemicals]

[chemistry - commission]

[consumers - cost]

[different - division]

[east - energy]

[filing - four]

[generation - gross]

[hello - impose]

[john - knowable]

[line - lowering]

[objection - okay]

[okay - p]

[patience - physical]

[reasons - reduction]

[reporter - resume]

[retail - robert]

[schmid - several]

[tax - testimony]

[transmission - understanding]

[understanding - utilize]

[v - washington]

(E) Submission to Witness; Changes; Signing. Within 28 days after being notified by the officer that the transcript or recording is available, a witness may sign a statement of changes to the form or substance of the transcript or recording and the reasons for the changes. The officer shall append any changes timely made by the witness.

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