PUBLIC SERVICE COMMISSION OF UTAH

Docket No. 20-035-04

CLOSING ARGUMENTS

December 04, 2020

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service-Regulations)	Docket No. 20-035-04

VIDEO CONFERENCED PUBLIC HEARING - CLOSING ARGUMENTS

TAKEN THROUGH ADVANCED REPORTING SOLUTIONS VIA ZOOM

Taken on December 4, 2020

9:01 a.m. to 12:27 p.m.

Reported by: Michelle Mallonee, RPR, CCR

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P R O C E E D I N G S

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CHAIRMAN LEVAR: Good morning. It is December 4, 2020, and we are here for the Public Service Commission of Utah hearing in Docket 20-35-4, application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and for approval of its proposed electric service schedules and electric service regulations.

Today is the day we've designated for closing statements. And based on those who filed briefs -- and again, closing statements were optional, so I don't know if everyone who filed briefs is planning to participate in closing statements. I would propose that we go in the order of Stadion LLC; then ChargePoint, Incorporated; then The Kroger Company; Utah Clean Energy; University of Utah; Utah Association of Energy Users; Office of Consumer Services; Division of Public Utilities; and Rocky Mountain Power.

Does anyone object to that order of closing statements, again, recognizing that some of the ones I listed might not be presenting closing statements?

I'm not seeing or hearing any --

MR. RUSSELL: No objection from me, Mr. Chairman. I might want to flip the order of UAE and the University of Utah just because the order of that presentation will likely be (inaudible) to combine those statements together, if that's okay.

CHAIRMAN LEVAR: I lost part of what you said, Mr. Russell. I'll just state that I had put those two together so that you could be in charge of how you wanted to handle them. If you needed to get what you just said on the record, I don't think we got it in the transcript.

MR. RUSSELL: No, that's exactly how I wanted to do it, so that's fine.

CHAIRMAN LEVAR: Okay. Thank you. I'm not seeing any objection.

I'm going to do one thing out of order. I have one question for Rocky Mountain Power that I'd like to put the question to you at this point so that you might be able to answer it as we get later in the day. It's just a technical question about whether a specific number remains confidential that was confidential in the testimony. So let me share that. I've written a quick summary of it. And let me just share that.

Are you seeing that screen, Mr. Moscon?

MR. MOSCON: Yes, it's -- yes, I see that. The surrebuttal, October 29 -- that question. Yes, I see that. Does that question -- does that number remain confidential, the one you've got redacted?

Let me find out, and I will either tell you when it becomes my turn, or do you need to know the answer to that before I would start presenting?

CHAIRMAN LEVAR: No. I was just hoping to get that answered sometime before we finish today.

MR. MOSCON: Okay. I will have an answer, and I will tell you before I go on to my closing statement.

CHAIRMAN LEVAR: Okay. Do I need to leave this on the screen any longer?

MR. MOSCON: No, thank you.

CHAIRMAN LEVAR: Okay. Thank you. Okay.

With that, I'll go first to Mr. Sanger, who indicated that you do not intend to make any closing statements.

Commissioner Clark, do you have any questions for Mr. Sanger?

COMMISSIONER CLARK: I do not. Thank you very much.

CHAIRMAN LEVAR: Okay. Thank you.

Commissioner Allen?

COMMISSIONER ALLEN: No questions. Thank you.

CHAIRMAN LEVAR: And I don't have any. So thank you, Mr. Sanger.

MR. SANGER: Thank you very much.

CHAIRMAN LEVAR: I do not see on the participant list anyone from ChargePoint. So unless someone states differently, I think we are not going to have a closing statement from ChargePoint.

Okay. With that, Mr. Boehm, would you like to make a closing statement on behalf of The Kroger Company?

MR. BOEHM: Thank you, your Honor. Kroger filed briefs in this case, and we will just submit our briefs and not do a closing statement. Thank you.

CHAIRMAN LEVAR: Okay. Thank you, Mr. Boehm.

Commissioner Allen, do you have any questions for Mr. Boehm?

COMMISSIONER ALLEN: No questions. Thank you.

CHAIRMAN LEVAR: Okay.

Commissioner Clark, do you?

COMMISSIONER CLARK: I have no questions. Thank you, Mr. Boehm.

CHAIRMAN LEVAR: Okay. I don't have any, either.

So, thank you for your brief you filed, Mr. Boehm.

MR. BOEHM: Thank you, your Honor.

CHAIRMAN LEVAR: And I'll go next to Mr. Holman.

MR. HOLMAN: Good morning, Chair. I don't have a closing statement prepared today, so I'm happy to answer questions.

CHAIRMAN LEVAR: Thank you.
Commissioner Clark, do you have any questions for Mr. Holman?
COMMISSIONER CLARK: No questions. Thank you, Mr. Holman.
CHAIRMAN LEVAR: Okay. Thank you.
Commissioner Allen?
COMMISSIONER ALLEN: Thank you. No questions.
CHAIRMAN LEVAR: And I don't have any, either.
So thank you, Mr. Holman.
MR. HOLMAN: Thank you.
CHAIRMAN LEVAR: We'll go to Mr. Russell next, then.
MR. RUSSELL: Thank you. Is my audio coming through better than it was earlier?
CHAIRMAN LEVAR: I am hearing you clearly. If anyone else isn't, please let us know.
COMMISSIONER CLARK: It's clearer for me.
MR. RUSSELL: Okay. Great. Thank you. I do have some closing statements to make. I intend to make them in the order of UAE's position with respect to revenue requirement first. And then I will go to the cost of service and rate design. As the testimony in the briefs that we have submitted on behalf of UAE and the University of Utah might indicate, there is some overlap,

and I intend to just make the discussion about Schedule 32, kind of combine it together. So that's how I intend to proceed.

CHAIRMAN LEVAR: Mr. Russell, with that, I think we will reserve questions from the Commission until you're completed with everything. I don't think we'll try to interrupt portions of that for questions.

MR. RUSSELL: However you would like to proceed. If I'm saying something that bores you and you would like to ask a question, please just interrupt me.

CHAIRMAN LEVAR: Okay. Well, if we have a burning need to, we'll interrupt you. Thank you.

MR. RUSSELL: Okay. Great. I will start where we started in UAE's post hearing brief on Rocky Mountain Power's proposal for a two-step rate increase. And this is tied to their -- the issue that they've had with delays regarding portions of the TB Flats 2 in Pryor Mountain Wind projects. What they're effectively asking this Commission to do is to have a separate test period for the delayed portions of those projects. Some portion of those projects will be in service by December 31st of this year, which is the first day of the 13-month average rate base for the test period that this Commission approved at Rocky Mountain Power's request. But some portion of those -- that plant will not be in service as of the first day of that test period, which means that the full annualized costs of those projects will not be included in rate base.

Rocky Mountain Power asked this Commission to use a separate test period to include the full annualized cost of the late portions of those -- of that plant in rate base. As indicated in our briefs, we believe that's inconsistent with Utah law and this Commission rule.

The Commission rules allow Rocky Mountain Power in advance of filing its application to request a particular test period and to submit testimony to support the test period that will most reflect the rate effective period. It did that, and the Commission approved the test period of the 12 months ending December 31st, 2021, with a 13-month average rate base.

Given the Commission's ruling, Rocky Mountain Power could then -- and I'm going to read from R746-700-10(B)(2), which allows the -- which says that after the Commission approves a test period in advance of the application, as it did here, quote, "the Applicant may then submit an application using as the test period for the case the test period previously approved by the Commission." It did that.

But in the course of this case, it learned that a portion of those -- the wind plant would be delayed.

And so instead of shifting the test period to account for the full annualized cost of those, shifting the test period for all costs, what Rocky Mountain Power proposes to do is to use a separate test period for some portion of the costs that are at issue. This is problematic because it does not allow this Commission to look at the full load of information that it would get about that separate test period.

So consistent with this Commission's ruling, approving a test period with the 12 months ending at the end of 2021, the Company submitted forecasted test period data for revenue requirement information, operating capital budgets, labor costs, et cetera. It also submitted a -- a cost-of-service study based on forecasted data for the test period.

The request to use a separate test period for isolated investments is inconsistent with the data that it has already submitted. That separate test period is also -- relies on forecasted data that is more than 20 months from the approved -- or from the application, which is inconsistent with Utah Code Section 54-4-4(3), which states that in establishing a test period, the Commission may use a future test period that is determined on the basis of projected data not exceeding 20 months from the date a proposed rate increase or decrease is filed.

The use of a separate test period also constitutes single-issue rate making. As I mentioned before, there's all sorts of information that the Company has to file so that the Commission gets a good sense of what's going on in the test period. You can't then take isolated investments and shift or use a different test period for those without engaging in single-issue rate making.

The Company asserts that the delays are a result of COVID-related delays and that it's not the Company's fault. All of that may be the case. There are particular tools that the Company can use to address these costs. But simply ignoring the law and ignoring Commission rules isn't one of them.

One of the things that the Company can do is to file a separate rate case later using a test period that would include these costs. Another thing it can do, if it qualifies, is to file for a major plant addition. The Company says, you know, Don't make us do that. It's a procedural hassle. But that's what the law requires. And the Commission should not in this case utilize a separate test period because it's not allowed to do so, and there are tools at the Company's disposal. Simply using a separate test period is not one of them.

The second issue I want to address is recovery of the Pryor Mountain project, as indicated in our testimony and in our brief. The recovery on that, if it's allowed, should be limited to the $26 per megawatt hour that the avoided cost rate allowed at the time the Company invested in the project. $26 is supposed to be the point at which customers are indifferent to whether the Company procures generation on its own or acquires it from others. The Company seeks recovery of more than that $26 per megawatt hour; and thus, the customers are not indifferent.

So, if approved, the Power Mountain Wind project should be a market resource where the Company gets to recover $26 per megawatt hour that it produces. It gets to keep its PTCs and the recs that belong -- that would then belong to the Company. And I will note that this proposal would not require the Commission or the Company to engage in the type of separate test period or other procedural rate making because it would get the $26 per whatever megawatt hour is produced when it's produced for the first 20 years.

I also want to address the issue that is at issue in the depreciation case and in the rate case, and that's the period of depreciation on the retired wind assets.

The retired wind plant should be depreciated over the remaining life of the repowered projects. The retirement of the repowered wind plant enabled the benefits from the repowering projects that will accrue to customers over the next 30 years. The cost of the retired wind plant should be paid for over that 30-year period to align the costs of the projects with the period in which the benefits would accrue.

The only party to disagree with this proposal is the Division. The Division indicates that it would prefer a 10-year depreciation period to align depreciation with production tax credits. The Division acknowledges that the PTCs are not the only benefits but asserts that, well, they're the most valuable ones. I'm not sure that they've actually demonstrated that point. But in any event, aligning the depreciation period of the retired wind assets with the PTCs does not eliminate intergenerational equity, which is the point that the Division wants to make.

The reason it doesn't eliminate intergenerational equity -- or inequity is that the customers in years '20 through '30 will have benefit of the repowered projects. It won't have to pay to replace the wind projects.

So the plant that was retired would have --

would have been in existence in service for the next 20 years. It had already been -- it had already been in use for 10 years. The expectation was that it would go another 20 and that it would be depreciated over another 20.

By retiring those wind assets and replacing them with new assets in the repowering projects, we've extended the life of the near zero marginal cost power for customers for another 10 years, which means that customers in that year 20 to 30 of the new repowering projects get the benefit of having that near zero marginal cost that they wouldn't have absent the repowering projects.

But under the Division's proposal, those customers who now no longer have to pay for the capital improvements to replace that wind would not have to pay for the retirement or the depreciation of the retired wind assets. We think that results in intergenerational inequity with customers in the next 10 years paying for a benefit -- paying for customers in years 20 to 30 that they don't pay for. So we think that the appropriate depreciation period is 30 years.

We have also, on the issue of the retired wind assets, we make two other recommendations, neither of which I intend to touch on unless the Commission has questions. One of them is for the depreciation of those retired wind assets to continue from the date of retirement, and the other relates to a 200 basis point reduction in the return on the investments to better align the balance of risks between the Company and its customers.

One last point on revenue requirement relates to the Company's annual incentive plan. As we indicated in testimony and in our post hearing brief, the annual incentive plan includes a portion that is tied to financial goals, and we just ask that this Commission affirm its long-standing position of declining to approve portions of annual incentive plans that include incentives that are based on financial goals. The rationale for that has always been that the primary beneficiary of such plans that are based on financial goals are the shareholders, and it is the shareholders who should pay for those types of incentive plans. And I just want to reiterate we don't have a problem with the Company including those types of incentives. Our point is that the customer shouldn't pay for them because they are not the primary beneficiary.

That's all I had on revenue requirement, and so I will shift to cost of service and rate spread.

UAE supports the Company's proposed rate spread, which reflects the results of the cost-of-service study while employing gradualism to balance the impact of rate increases across rate classes. In its post hearing brief, Rocky Mountain Power cites Utah Code Section 54-3-1. And I think it bears repeating. That statute states that utility rates and charges must be just and reasonable, taking into consideration "the cost of providing service to each category of customer, economic impact of charges on each category of customer and on the well-being of the state of Utah, methods of reducing wide periodic variations in demand of such services, and means of encouraging conservation of resources and energy."

We believe that the Company's rate spread appropriately balances all of these considerations and request that the Commission approve it.

Our post hearing brief includes some statements with respect to -- or some arguments with respect to adjustments that the Office had proposed to the embedded cost-of-service study. I don't intend to repeat those here. We spent a fair bit of time on them, but I'm happy to answer any questions.

Finally, I will address the proposed rate design for Schedule 32. UAE and the University of Utah proposed to set the Schedule 32's delivery facilities charge at the rate set for the corresponding full requirements rate schedules. This is consistent with the Commission's ruling in Docket No. 14-035-T02 in which the Commission adopted UAE's proposal to set the delivery facilities charge at a rate that ensures that Schedule 32 customers do not pay different effective rates for delivery services than their full requirement rate schedule counterparts.

The Company's proposal is to set the delivery facilities charge to recover the full amount of fixed transmission costs identified in the cost-of-service study for the full rate requirement schedules. This results in an increase to that charge of approximately 30 percent for transmission voltage customers. This is the same proposal that the Company advanced in Docket No. -- in that previous docket number that I mentioned, 14-035-T02, the docket in which this Commission adopted Schedule 32.

The Commission declined to adopt Rocky Mountain Power's proposal in that docket and should do so again now.

It remains true that the Company's proposal, as it did in the previous docket, would impose different effective rates for delivery service on Schedule 32 customers than would be imposed on corresponding full rates requirement schedules. It is also true, as the

Company states in its post hearing brief, that this Commission takes many things into account in setting rates. The cost-of-service study is one of them, but it is not the only one.

The rate spread is intended to bring customers closer to the cost of service, but it doesn't do that, not perfectly. It doesn't align perfectly for any of the full rate requirement schedules. So it doesn't make sense to charge Schedule 32 customers a delivery facilities charge based on the notion that they'll pay full cost of service either. That's not how the Schedules 6, 8, and 9 are set up, and it's not how Schedule 32 should be set up.

The Company seeks to justify its position by claiming that Schedule 32 has daily power charges that a Schedule 32 customer could avoid; and therefore, that Schedule 32 customers could underpay delivery charges. But the Company has not demonstrated that there are sufficient opportunities for a Schedule 32 customer to avoid daily power charges that would result in an underpayment of delivery charges.

As we note, as we've noted throughout this case, the Company did not perform a cost-of-service study for Schedule 32. It did not because there wasn't enough information. It didn't have enough data from a single

Schedule 32 customer on that rate schedule to do so in the base test period.

In addition to the fact that there is no cost-of-service study on which the Company can rely to support its position here, the fact remains that peak hours stretch well into the nighttime. And so any proposed Schedule 32 customer that intends to rely on renewable energy that is intermittent will have a very difficult time avoiding daily power charges in the way that Rocky Mountain Power suggests.

The Company's claim that Schedule 32 customers' ability to avoid delivery charges is also mitigated by the fact that Schedule 32 has a 300-megawatt program cap. As I mentioned, there's only one customer, and that's the University of Utah. The rate schedule has been around since 2015. The fact that there's a single customer suggests that Schedule 32 is not some economic boon to parties. It is available to parties like the University of Utah who have zero carbon goals. But those customers are not flocking to Schedule 32 to make a buck. They're going to Schedule 32 because it's the only viable schedule for them, for large customers, to meet the types of sustainability goals that the University of Utah has.

The cap on this program, 300 megawatts, will mitigate any impacts that there theoretically could be from some future larger adoption of this program.

In our brief, we also pointed to the fact that the Company treats Schedule 32 customers differently than it treats Schedule 31 customers. We note that the Commission in its order approving Schedule 32 drew some parallels between these two rate schedules. They're both partial requirements rate schedules. They both have daily demand charges.

But the Company does not propose for Schedule 31 to set a facilities charge at the full rate requirements cost-of-service revenue requirement for fixed transmission costs. Instead, it sets the facilities costs at a rate that's a fair bit closer to the full rate requirements, Schedules 8 and 9, than even the current Schedule 32 costs. And there is no evidence that Schedule 31 customers have avoided their daily demand charges in a way that shifts costs. And there isn't any -- as I mentioned, that Schedule 32 customers would result in the same -- would result in that underpayment of delivery charges.

So, in short, the Company's proposal would treat Schedule 32 customers differently than the full rate requirement schedules. It would treat them differently than other partial requirements customers. And we don't think that there's any demonstration that this is a necessary or a prudent proposal.

And we ask that the Commission approve the proposal of UAE and the University of Utah because we think it most closely adheres to the Commission's ruling in Docket 14-035-T02.

One last point on the University of Utah. It has some equities here that are unique to it given the fact that it is the only Schedule 32 customer. As mentioned in the testimony, it has entered into two separate Schedule 32 contracts, one with a geothermal project that began delivering power under Schedule 32 in 2019, another very recently it entered into a 20 megawatt solar project that will not begin delivering power under Schedule 32 until 2022. Those are long-term commitments. These long-term commitments were made to make progress towards the University's goal of carbon neutrality by 2050, but also because of the University's belief that Schedule 32 customers would be treated equitably with respect to the rates that they are to pay.

I mentioned that this Commission drew a parallel with Schedule 31 when it adopted Schedule 32. And in doing so, in the report and order in that prior case, it indicated that, and I'm quoting here, "Additionally, we recognize prospective customers will be using Schedule 32 to make long-term resource decisions. For these reasons, we find it reasonable to adopt a rate design for Schedule 32 that both achieves the objectives of SB12 and maintains a measure of consistency with the way currently approved rates and schedules address demand charges."

The Company's proposal seeks to radically change the way that Schedule 32 addresses demand charges. The University of Utah's proposal would have the Commission set those demand charges at the same rate as the full rates requirements customers, which is, we believe, what the Commission had intended with the prior order.

And I'll just note the University's position here is similar to UAE's, but the University, as indicated in the testimony of Mr. Christopher Benson, did not enter into Schedule 32 to avoid demand charges. That's not his point. In fact, its economic analysis of Schedule 32 would be just about a break even, you know, in getting into Schedule 32 versus getting power from the -- from the Company. This is not designed in the way that -- their intentions here are not to avoid those delivery charges in the way that Rocky Mountain Power proposes Schedule 32 customers would.

And with that, I will submit on behalf of UAE and the University of Utah. And I'm happy to answer any questions.

CHAIRMAN LEVAR: Thank you, Mr. Russell.

I'll go to Commissioner Allen first.

Do you have any questions for Mr. Russell?

COMMISSIONER ALLEN: No questions. Thank you.

MR. RUSSELL: Thank you.

CHAIRMAN LEVAR: Thank you.

Commissioner Clark?

COMMISSIONER CLARK: I have no questions. Thank you, Mr. Russell.

CHAIRMAN LEVAR: Okay. Thank you. I have a couple.

You briefly spoke about UAE's position on the employee incentive plans, and you described your interpretation of prior Commission precedent. And I just want to clarify that.

Is it your interpretation that the previous Commission orders on this issue stated that they would disallow any portion of an employee incentive plan that was focused on financial goals, or was the Commission precedent that they would not allow an incentive plan that was predominantly based on financial goals?

MR. RUSSELL: My understanding is that the Commission's prior rulings on this point have, in fact, approved annual incentive plans but only those portions of the annual incentive plans that are not based on financial goals.

In the 2008 case -- and I think this would be found in the transcript of Mr. Higgins' live testimony on redirect -- we cited to some of the positions that the Company had proposed. And in the Commission's ruling with respect to that annual incentive plan, there was a portion of that annual incentive plan for executives. In fact, there was the annual incentive plan for executives I think that was primarily based on financial goals. And the Company was not seeking recovery of those. But for the employees, the nonexecutives, there was a portion of that that was based on financial goals.

And my understanding of the Commission's ruling there is that it approved only those portions that were not based on financial goals.

I hope that answers your question. I don't think that the Commission's prior rulings are based on this notion that it has to be primarily based on financial goals. The Commission has kind of siphoned off those portions that are based on financial goals.

CHAIRMAN LEVAR: Okay. Thank you. That answers my question.

MR. RUSSELL: Okay.

CHAIRMAN LEVAR: And then I have one more question for you, and it's on Pryor Mountain. And I'll recognize that UAE's testimony on this issue doesn't go to my question as directly as some of the other parties. But I want to give you, the Division, the Office, and Rocky Mountain Power all the opportunity to answer the same question.

So in your view with our statutory standards for evaluating the prudence of Pryor Mountain, do we need to see modeling that demonstrates it was beneficial to ratepayers on a basis of comparing with or without Pryor Mountain? Or do we need to see modeling that demonstrates it was beneficial to ratepayers as compared against all other reasonable, knowable alternatives?

MR. RUSSELL: It's a really good question. I think the Company has in the past several years sought to justify certain projects on the basis of their economics. And we've been through this with the repowering projects and with the new wind projects from EV2020, where they've demonstrated, you know, here's our glide path. Here are these projects. Here's what revenue requirement looks like if we don't do these projects versus if we do them.

So the trouble that some of the customer groups like UAE and others have had is that the assumption here is that those are the only projects that are available. And so -- and that's certainly just not the case. There are other projects out there, as we've seen from the current RFP.

I think it -- it is incumbent on the Company to demonstrate when it's seeking to justify a project like this one, particularly when it's a single project like this one, that it is the best available project in that there's some need.

Now, the Company is justifying this project not because it needs the capacity or the energy, but because it represents an opportunity for customers. In those circumstances I think it is incumbent on the Company to show, Look, it's a benefit to the customers, and it's -- there's not some better project out there that we could have gone out and gotten a PPA on or something else that would represent a better -- you know, better value for customers.

So I think the answer to your question is yes, they do need to show that, particularly in these circumstances where it's purely based on an economic opportunity rather than some need that's out there that has, you know, kind of a ticking clock to it.

CHAIRMAN LEVAR: Thank you. That's all the questions I had for you, Mr. Russell. So, thank you for your time this morning.

MR. RUSSELL: Thank you.

CHAIRMAN LEVAR: I'll go to the Office of Consumer Services next.

MR. MOORE: Hello, Commissioners. Can you hear me and see me? This is Robert Moore.

CHAIRMAN LEVAR: I can see and hear you clearly.

MR. MOORE: If it is all right with the Commission, the Office would like to divide the time between myself and Mr. Snarr. I'll be doing the cost of capital portion of the presentation and a little bit of the revenue requirement, while Mr. Snarr finishes the revenue requirement and does the cost of service.

CHAIRMAN LEVAR: Okay. Would you prefer that we ask any questions of you one at a time, or would you prefer that we let both of you finish everything, and then we can ask any questions we have for either of you?

MR. MOORE: However is easiest for the Commission.

CHAIRMAN LEVAR: Okay. Why don't you go forward. If we need to stop and do questions after one of you, we will; if not, we might just wait until you are all finished.

MR. MOORE: Good morning, Commissioners.

I'd like first to address Rocky Mountain Power's assertion made in their post hearing brief that recent market conditions which are more volatile because of the pandemic justify a higher ROE. This contention conflicts both with the 2020 general rate cases for electric utilities and Rocky Mountain Power's own economic modeling.

First, the OCS agrees with Rocky Mountain Power that current marketing conditions are a critical consideration in determining ROE. However, any pandemic-related volatility has been coupled with a low interest rate environment. This low interest rate environment is forcing ROEs lower rather than volatility forcing ROEs higher. This is evidenced by the ROE regulatory focus survey of general rate cases in the first nine months of 2020, introduced by DPU Cross Exhibit No. 1, which states that the average ROEs for 2020 is 9.44 percent.

The Office reports state: "ROEs ... are at the lowest level ever witnessed in the industry, and with the recent interest rate cuts by the U.S. Federal Reserve and current pandemic-induced recession even lower authorized returns may be on the horizon."

The report goes on to state that while "federal fund rates do not move in lockstep with long term treasuries and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs change in a similar fashion."

Moreover, the Federal Reserve has announced that it plans to continue with its interventionist policies and keep interest rates near zero right through 2023. Therefore, while current market conditions are critical factors to consider, the market conditions are dominated by a lower interest rate environment and argue for lower ROEs.

Second, the contention that recent market conditions justify higher ROEs is inconsistent with Rocky Mountain Power's own modeling. On page 3 of its post trial brief, Rocky Mountain Power asserts utility industries are underperforming. However, on page 25 and 26 of Ms. Bulkley's post-pandemic rebuttal testimony, she claims the utility stocks are not underperforming but, rather, are overvalued. This contention that utility stocks are overvalued is necessary to explain her disregard of Professor Woolridge's, Mr. Coleman's, and ultimately her own DCF analysis.

Specifically, her DCF analysis is based on the contention that DCF models should be not given much weight because utility stocks are presently overvalued and interest rates are too high -- too high -- too low, and therefore, the results of the DCF's balances are unreliable. Therefore --

CHAIRMAN LEVAR: Mr. Moore, I think we may need you to repeat some of that. When you were turning pages, it was causing noise. I don't know if Ms. Mallonee was able to get everything you said. Maybe if you could repeat a little bit of the last few sentences.

MR. MOORE: Certainly. Specifically -- is this a good place to start? Well, let me start back up again.

The contention that utility stocks are overrated is necessary to explain Ms. Bulkley's disregard for Professor Woolridge's, Professor Coleman's, and ultimately her own DCF analysis.

Specifically, her DCF analysis is based on the contention that DCF models should not be given much weight because utility stocks are presently overvalued and interest rates are too low.

Therefore, the contention that more volatile market conditions result in an underperforming utility industry and justifies higher ROE conflicts with Rocky Mountain Power's economic modeling. Again, as evidenced in 2020 authorized ROEs, current market conditions are dominated by lower interest rates, yields, and lower ROEs.

Another factor arguing for lower ROEs is Rocky Mountain Power's request for a capital structure of 53.67 percent equity. The OCS has demonstrated that this level of equity is well above the proxy group's equity percentage of approximately 44 percent and the equity percentage of Rocky Mountain's parent, Berkshire Hathaway, is approximately 42 percent.

As the Commission is well aware, capital structure is interrelated with ROEs. They are two sides of the same coin. That is because debt is riskier than equity. As equity increases and debt decreases, risk will decrease, leading to a lower ROE.

In addition, equity is more expensive than debt. So if the equity percentage of the capital structure is increased and the ROE remains constant, revenue requirement will necessarily increase.

The impact of revenue requirement caused by increased equity percentage can be dramatic. By way of example, the OCS has taken the Washington settlement capital structure of 49.1 percent equity and the Washington settlement's ROE of 59.5 percent and the OCS revenue requirement calculations and demonstrated that if the capital structures in the settlement was increased to Rocky Mountain's request of 53.67 percent equity, in order to keep the revenue requirement and change, the ROE would have to be reduced to 9 percent. This is consistent with Mr. Woolridge's recommendations.

These two facts, that the ROE decreases and debt goes down and the impact on the revenue requirement of increasing equity, require regulatory commissions, when faced with a request for higher equity position, do one of two things: Lower the ROE or impute debt to a hypothetical capital structure.

This is what the OCS has recommended. This analysis is not directly contested. Rather, Rocky Mountain Power argues that its equity position is not high when compared to the equity position of the operating companies in the proxy groups of holding companies. However, this contention is an incorrect approach.

The proper approach is to compare Rocky Mountain Power's equity position with the actual proxy groups, the holding companies because, one, the holding companies have market information necessary to run the economic modeling. And two, the interrelationship between capital structure and ROE; that is, the risks associated with the holding companies' ROE, reflects, in part, the holding companies' lower equity percentages. If the holding companies had the higher percentage, the operating companies' risk would be reduced, and the ROEs would have to be lowered.

Therefore, in order to reflect the risk associated with the proxy companies used for the ROE analysis, it is necessary to use the proxy companies' capital structure in comparing the appropriate equity position.

It is also of note that Rocky Mountain's requested 53.67 equity is higher than its current authorized capital structure of 51.43 percent equity, Rocky Mountain's current actual equity percentage of 51 percent, and the equity percentage of Rocky Mountain Power's Washington settlement of 49.1 percent, and the average authorized capital structures of electric utilities in general rate cases in 2020 of 49.37 percent. Accordingly, if the Commission is supposed to grant Rocky Mountain Power their requested equity position, because of their higher-than-average capital structure, they must be given a lower-than-average ROE.

A third element that justifies a lower ROE is Rocky Mountain Power is less risky than the proxy group companies, as evidenced by its superior credit rating. Rocky Mountain Power S&P rating is A, two notches above the average S&P rating of BBB+ of the proxy group companies. And Rocky Mountain Power's Moody's rating is A3, one notch above the average Moody's ratings of Baa1 of the proxy companies.

Rocky Mountain Power nevertheless argues that it is riskier in the industry because of the regulatory environment in Utah, capital expenditures, generation ownership, the Tax Act of 2017, et cetera. However, all these factors, even the fact that Rocky Mountain Power is a vertically integrated utility, was taken into consideration by the rating agencies when they gave Rocky Mountain Power a superior credit rating. Thus, Rocky Mountain Power's argument regarding these risk factors fails. And the fact that Rocky Mountain Power is less risky in the industry also argues for a lower ROE.

Finally, Rocky Mountain Power's claims that their proposed ROE of 9.8 percent is consistent with the authorized ROEs is simply incorrect. As previously stated, the ROEs in rate cases cited in the first nine months of 2020 under current market conditions are the lowest ever seen in the industry.

Today, for 2020, vertically integrated electric utilities have average ROEs of 9.54 percent, and for all electricity -- electric utilities, the average ROE is 9.44 percent with an average equity percentage of 49.37 percent. The higher average that Rocky Mountain Power proposes -- to get the higher averages that Rocky Mountain proposes, Rocky Mountain Power relies on stale ROE analysis from 2008 and 2017 when interest rates were higher and before the pandemic and before the Federal Reserve actions that have taken place in 2020.

Taking recent market conditions into consideration and the lower risks associated with high equity position and the high credit rating, OCS's position is consistent with the 2020 authorized ROEs.

The starting point for vertically integrated utilities is 9.54 percent. This must be significantly reduced because of Rocky Mountain Power's high equity position, then reduce again because Rocky Mountain Power is less risky, as evidenced by its credit rating. These two reductions should bring the ROE down to a level the OCS recommended of 9 percent. In any event, these reductions must drive ROEs significantly below 9.5 percent to be comparable with authorized ROEs in 2020.

That's the end of the cost of capital portion of the OCS's presentation. Would you like to ask any questions now?

CHAIRMAN LEVAR: Commissioner Clark, would you like to ask Mr. Moore any questions at this point about cost of capital?

COMMISSIONER CLARK: No, I have no questions. Thank you, Mr. Moore.

CHAIRMAN LEVAR: Okay. Thank you.

Mr. Allen -- I mean Commissioner Allen?

COMMISSIONER ALLEN: I have no questions either. Thank you.

CHAIRMAN LEVAR: And I don't either about this issue. So why don't you continue on, Mr. Moore.

MR. MOORE: Now I would like to touch briefly on the pension issue in the revenue requirement portion of these proceedings.

There are three issues to touch upon in addressing pensions. One, the treatment of settlement losses; two, the inclusion of revenue requirement and prepaid pension assets and other post retirement assets; and three, the alternative recommendation of a pension balancing account.

First, with regard to the pension loss, the OCS and UAE are recommending that RBM -- recommending that Rocky Mountain Power amortize settlement losses or gains over the remaining life expectancy of plan participants. Under such an approach, the settlement losses or gains will continue to be recognized in annual pension costs, the same way they would have been recognized had the recognition of the settlement loss or gain not been triggered. This is consistent with the treatment of Rocky Mountain Power's request in Docket 18-035-48. It was recognized as a valid approach by Rocky Mountain Power in the hearing and does not reasonably -- unreasonably inflate the revenue requirement.

Second, Rocky Mountain Power's recommendation to include prepaid settlement assets into the revenue requirement must be rejected. Rocky Mountain Power's prepaid asset approach is a radical departure from past practices, and Rocky Mountain Power has not provided any new facts and rationale to justify this inconsistency, as required by Utah Code 63G-4-403(4)(a)(iii).

While over the duration of these retirement plans, the total amount of cash contributions to the plans will ultimately equal the total amount of expenses associated with the plans, it is unfair to charge ratepayers a return now that the Company is in a net prepaid position when ratepayers did not benefit through a reduction to rate base during the many past years in which the net -- an accrued liability existed.

While Rocky Mountain Power claims that its shareholders have funded the net prepaid asset, it is unable to support this claim. It cannot be determined if the prepaid balance on Rocky Mountain Power's books was funded by shareholders or ratepayers because many cases were resolved in settlements. For these reasons, Rocky Mountain Power's prepaid argument must be rejected.

Finally, the Commission must reject Rocky Mountain Power's suggestion of establishing a pension balancing account. This suggestion of a pension balancing account was first mentioned by Rocky Mountain Power in its rebuttal testimony approximately a month before the hearing, and Rocky Mountain Power has not adequately supported its new-found position.

Moreover, pension costs are not sufficiently variable to justify a balancing account, and the proliferation of balancing accounts is contrary to policy considerations against single-issue rate making.

Mr. Snarr will continue with the OCS presentation from here. Thank you very much, Commissioners.

MR. SNARR: Thank you. I'd like to talk about some of the other revenue requirements issues, and then I'll move into some of the cost-of-service rate design issues, if that will be all right.

First, I'd like to discuss the Pryor Mountain project. The OCS recommends disallowance of the Pryor Mountain costs because, first, it is not strictly needed by Rocky Mountain in its resource requirements; second, it is more expensive than other recent acquisitions, and the Company has really made no comparison to other alternatives; and thirdly, it is based on an affiliate transaction that has not been fully justified.

The Company's testimony states that when the Company made its decision to proceed with the Pryor Mountain project, it ran its GRID model and found that the system would be better off with the project than without the project. Such analysis is incomplete. If three projects passed the GRID test, would they add all three? Or, if 15 projects passed their GRID test, would they add all 15?

As a regulated utility, Rocky Mountain has an obligation to consider whether another energy resource is really needed. The Company has not demonstrated a need for the project, given the availabilities of front office transactions and the pending large solicitation for renewable resources.

In addition, there are burdens that Rocky Mountain must assume as a regulated entity that demonstrate that its decision would meet a public interest standard. Rocky Mountain was fully aware of the need to demonstrate prudency in connection with, first, the decision it made to proceed with the Pryor Mountain project; second, the acquisition of wind turbine components from an affiliate, including regulatory scrutiny in acquiring the equipment at cost or market; and lastly, the incurrence of actual cost overruns. This awareness is demonstrated by the testimony of Joelle Steward at the hearing.

Notwithstanding this awareness, the Company failed to include any explanation or evidence in its rate case application that addressed questions about availability of comparable energy supplies or whether the Pryor Mountain facility would be an energy source that would produce energy at the lowest reasonable cost.

The OCS is not suggesting a different standard for approval of Pryor Mountain because the Company chose not to seek preapproval. Rather, since no review of prudence has been made to date, a full prudence review of both planning decisions and construction costs must take place in this proceeding with the Company bearing the burden of proof before this Commission -- before this Commission can authorize a recovery in rates of Pryor Mountain related costs.

While the Company chose to proceed without seeking preapproval of the project, under Utah Code Section 54-17-201, it cannot avoid prudency scrutiny as it relates to the public policy that is embodied in that statute requiring utilities to consider whether its actions will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable costs to retail customers. That policy remains a legitimate concern when considering whether a utility's decision is prudent.

Our Utah Supreme Court has stated that the utility bears the burden of presenting the evidence necessary to support the Commission's essential findings.

In the 2003 case involving Committee of Consumer Services versus the Commission, the Court specifically stated, "In the regulation of public utilities by governmental authority, a fundamental principle is the burden rests heavily upon a Utility to prove it is entitled to rate relief and not upon the Commission, the Commission staff, or any interested party or protestant to prove the contrary. The Utility must, therefore, put forth substantial evidence to establish that its proposed increase is just and reasonable. The Commission, in turn, bears the responsibility for holding the Utility to its burden."

Similarly, in a 1980 case before the Court, Utah Department of Business Regulation versus Public Utilities -- Public Service Commission, the Court stated, "Ratemaking is not an adversary proceeding in which the Applicant needs only to present a prima fascia case to be entitled to relief. A state regulatory commission must be informed of all relevant facts."

The Company's application also failed to include any evidence showing the market value of the wind turbine components it was acquiring from its Berkshire Hathaway affiliate. Rocky Mountain provided no evidence of any evaluation that the price paid was the lower of cost or market for critical wind turbine components, the hubs and the nacelles the Company decided to use from its affiliate. Without that evidence, it appears that the sale was an opportunity for an affiliate to offload wind turbine components that were simply sitting in storage at the time when their value was declining because PTCs were expiring.

Commissioner Clark questioned Rocky Mountain's witness, Mr. Van Engelenhoven, related to this market value, and no evidence was presented as to the market value in 2019 as it related to the purchases that had been made by the affiliate in 2016 at book value.
Mr. Engelenhoven in the hearing discussed this, and when pressed on cross, indicated that -- in response to a question whether they had zero value, he could only state that the wind turbine components had some value.
Mr. Hayet also addresses this in his hearing testimony.

Now, the Utah Commission has required utilities to specifically address questions of prudency when dealing with affiliate transactions. In a 1990 case involving Mountain Fuel Supply, the Commission said, "The Commission is of the view that transactions involving affiliates place ratepayers at a disadvantage that can never be entirely controlled or offset. For that reason, it is generally appropriate to allow transfers of property from affiliates to the utility at the lesser of book or market and transfers going the other way at the greater of book or market. We find that Mountain Fuel's property transferred to an affiliate should be valued at the greater of market or book, while that transferred from an affiliate to Mountain Fuel should be valued at the lesser of market or book."

Another concern has emerged as this case has progressed. Cost overruns have been disclosed, and there's been no evidence presented addressing the prudency of such cost overruns. Specifically, look to Mr. Link's hearing testimony when he addressed this in questioning as well as Mr. Higgins's hearing testimony.

Contrary to the Company's assertion that OCS has mischaracterized the burden of proof requirements that Rocky Mountain must meet, we acknowledge that the question of prudency is one that requires us to consider evidence of prudency at the time the Company made its decision to move forward with the Pryor Mountain project. We submit, however, that the Company has failed to meet its burden of proof in that there is no evidence showing a need for the Pryor Mountain project, no evidence that that might provide -- that it might provide energy at the lowest reasonable price, and no evidence that the turbine components requiring -- that the turbine components acquired from the affiliate were acquired at the lower cost or market.

In addition, in seeking to recover overrun costs in this proceeding, the Company has failed to provide any evidence to support a finding of prudency related to those overrun costs. For these reasons, the OCS maintains that the Company has failed to satisfy its burden of proof demonstrating that it is entitled to recover the costs in the Pryor Mountain project.

Some of the concerns we've expressed are similar to the concerns that have been expressed by UAE in its brief and in the hearing today. UAE, however, has focused on the legality of an extended or separate test year. That seems to bring into focus the questions about costs and when those costs will be finally determined, when they'll be known and measurable. The UAE has also focused on the competitive price that was attached to the project prior to Rocky Mountain acquiring it, which seems to also focus on whether or not there was any comparable studies made of other alternative supplies at the time and whether this project might be one that will produce energy at a lowest reasonable cost.

For these reasons, we submit that the Pryor Mountain costs included in this case should be excluded and based upon a failure of the Company to meet its burden of proof.

We've also raised issues about the Lake Side 2 outage. In our brief, we've set forth our position. It is unfortunate when outages occur. When they occur twice in the same facility in similar ways and for similar reasons, these outages need to stop. These facts leave us with a mystery that must be solved by Rocky Mountain before the next outage. The evidence demonstrates the need for Rocky Mountain action. It does not meet the burden of proof required to demonstrate prudence. The DPU is aligned with the Office on this issue.

We have four other issues that we've addressed, which I'll identify here: The transmission power delivery, bad debt, generation overhaul expense, nonlabor O&M escalation, and the Deer Creek Mine regulatory asset. For each of these four issues, the OCS has presented clear evidence through its witness, Donna Ramas, demonstrating a basis for the suggested adjustments to the Company's revenue requirement. We provided a factual summary and legal basis for making these adjustments in our legal brief.

I would note that UAE's witness, Kevin Higgins, in his direct testimony at page 53 provides support for the adjustment we suggest as it relates to the Deer Creek Mine regulatory asset. Interestingly, Rocky Mountain has chosen not to address these four issues in its post trial brief.

I'd like to now turn to the AMI meters. This is an issue that seems to have found its way into both the revenue requirement section of the case as well as the cost of service rate design. I'll address it once here.

The OCS recommends that the Company's Utah AMI project be excluded from the test year as the benefits of the project are largely not expected until 2023 when the project is fully implemented. The purported benefits and offsetting cost savings are not reflected in the test year, and the project will not be fully used and useful in the test year.

Actual amounts spent on the Utah AMI project assets completed and being placed in service during 2020 are only expected to be less than about 2.5 million, as indicated in Mr. Mansfield's hearing testimony. Without the realization of significant benefits in the test year or the inclusion of any of the purported benefits and cost offsets in the test year, the recovery of the costs should not be allowed in this rate case.

The Company's justification for the project has been primarily focused on possible improvements to the meter reading process. AMI meters can be a grid modernization tool, but without proper analysis, planning, transparency, and accountability, customer benefits will not be realized, and the project will not be cost effective.

The OCS recommends that Rocky Mountain develop an advanced rate design roadmap to ensure that AMI functionality provides benefits for ratepayers as soon as is reasonable. The Division supports our position. UCE supports our suggestion for further collaborative studies with stakeholders. And WRA, while not filing a post hearing brief, supports our suggestion as well.

I'd like to now turn to Rocky Mountain's cost-of-service study. The OCS has examined Rocky Mountain's cost-of-service study and found that the Company's modifications to traditional cost-of-service methods to incorporate subfunctionalization is fatally flawed, inappropriate, and without transparency shifting costs from energy to demand. Using the study could have additional unintended consequences.

One of the guiding principles recognized by regulatory authorities in designing rates for regulated utilities is cost-causation. That principle has been described in the U.S. Court of Appeals for the District of Columbia as requiring that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them."

In elaborating further on this cost-causation principle, that Court explains: "In the context of monopoly regulation, this principle helps ensure that utilities produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer. That is, we scrutinize a utility's rates to ensure a match between cost-causation and cost-responsibility." That's from the Black Oak Energy case cited in our brief.

Such cost-causation principles have been followed in Utah regulatory proceedings where utilities have been required to perform cost-of-service studies in support of their proposed rate designs. And we cite in our brief the PSC order of 1995 involving U.S. West.

In the cost-of-service study submitted by Rocky Mountain, the Company claims to have followed traditional steps of analysis where costs are first functionalized, then classified, and finally allocated to inform rate design. However, the technical mechanics of Rocky Mountain's fixed and variable subfunctionalization and changes made to facilitate unbundling are not an accepted or recognized cost-of-service approach.

Rocky Mountain not only failed to provide sufficient detail and support for its subfunctionalization, but its methods are also highly flawed, both technically and theoretically.

Subfunctionalization's purpose is to better reflect cost-causation. But when it does not change the classification and allocation of costs, costs cannot be more accurately categorized into energy, demand, or customer-related, nor split between customer classes.

In its legal brief, Rocky Mountain claims that OCS has just misunderstood what Rocky Mountain was doing to accomplish unbundling. A brief response to this accusation may be in order.

In his direct testimony, Mr. Meredith states that unbundling provides stakeholders with useful information on how rates recover different aspects of the utility service. This information can be helpful in different rate making contexts, such as when designing new programs for alternative generation sources.

In his rebuttal testimony, Mr. Meredith introduces EBA clarity as a primary reason for unbundling. Nowhere in his prefile testimonies does Mr. Meredith mention anything about programs envisioned by H.B. 411. However, in his witness statement presented at hearing, Mr. Meredith, for the first time, mentions that unbundling will allow delivery costs in rates to be delineated from supply so that programs like those envisioned in House Bill 411 can be designed.

Subsequent to Mr. Meredith's witness statement, Rocky Mountain is now claiming in its legal brief that unbundling is a necessary step to support programs that have been envisioned by House Bill 411.

So, as OCS and others have been attempting to follow the Company's ever-changing rationale for its unbundling, Rocky Mountain suggests that we are all confused. Rocky Mountain would also have us believe that this ever-changing story somehow satisfies the Company's burden of proof in proposing and justifying a new procedure to be used in establishing rates.

Rocky Mountain's subfunctionalization proposal is not transparent. In fact, it is an attempt to work around the long-standing 75/25 demand and energy split precedent for production and transmission classification. To achieve the workaround, Rocky Mountain creates unprecedented cost components referred to as "fixed and variable supply."

According to the Company, cost-causation principles would support recovery of fixed supply costs through demand rates because of the fixed supply cost -- because the fixed supply cost component is greater than the costs traditionally classified as "demand related" within the embedded cost-of-service study. Rocky Mountain's approach could be used to justify inflated demand charges and lower kilowatt hour charges. Using contrived cost components that do not follow cost of service best practices is clearly a deviation from traditional cost-based rate making. Simply stated, the variable supply, or EBA costs are not the same as the energy costs within the cost-of-service study that Rocky Mountain uses the EBA costs to alter rate design.

EBA costs do not equal energy-related costs. Even though Rocky Mountain characterized the changes as being made to its cost of service as helpful for unbundling, Rocky Mountain's proposed fixed and variable cost subfunctionalization is technically unsound, creates significant confusion through a lack of transparency, and represents an unprecedented move away from cost of service based rate making.

Various witnesses representing different parties acknowledged reviewing Rocky Mountain's cost-of-service study as part of their analysis presented in this case. However, most of those witnesses also acknowledge that the subfunctionalization step proposed by Rocky Mountain presented confusion and should not result in changes to the separate steps of functionalization classification, and allocation of costs.

Witnesses also acknowledge the lack of transparency and understanding as it relates to Rocky Mountain's claim that it was necessary to make the change to incorporate unbundling, a step that was not fully explained, supported, or justified by the Company, unless you're going to use their latest rationale stemming from the witness statement at the time of the hearing and their legal brief, as they're now contending.

Without providing clear evidence of the need for the extra step of subfunctionalization, and without a cogent explanation as to what was being accomplished by the Company's unbundling change, the evidence presented by Rocky Mountain fails to satisfy the Company's burden of proof to support its proposed rate design. Thus, the PSC should reject Rocky Mountain's proposal for unbundled rates.

Now, the OCS does not oppose unbundling per se, but submits that Rocky Mountain's specific proposal for unbundling is not in the public interest, a conclusion supported by several other parties in this proceeding. Further, given the weaknesses of Rocky Mountain's cost-of-service study along with additional evidence presented by OCS, the PSC should give consideration to factors other than just the Company's cost-of-service study in deciding how to allocate costs to the various customer classes. There's record evidence available for the PSC to carefully review and consider the relative performance of customer classes in providing revenues compared to the costs that have been assigned to each class. In that regard, please see Witness Nelson's rebuttal testimony at page 26.

There is also evidence relating to likely increases in residential revenues in light of the effects of the pandemic that customers have been recently experiencing. These facts, along with equitable considerations associated with gradualism, can easily form a framework from which the PSC can prescribe a fair and equitable approach to be taken in the design of rates as opposed to relying upon the flawed and unpersuasive cost-of-service study that was submitted by Rocky Mountain.

We would note that the UCE says that changes to facilitate unbundling should be accomplished through a collaboration with stakeholders. And Salt Lake City, while they did not file a post hearing brief, generally also supports this position.

Lastly, I'd like to just speak a little bit about residential rates. Rocky Mountain's suggested rates for residential service incorporate increases to residential customer monthly service charges combined with the elimination of the last rate tier, which together result in an inequitable imposition of increased rates for customers with lower and average levels of use.

The OCS examined Rocky Mountain's proposed rate design as it might affect the rates of residential customers, with particular focus of ensuring that no subset of the customer class is burdened with an unreasonably high rate shock.

While the OCS generally supports the Company's suggestion to split the basic monthly service charge between multi-family and single family customers, OCS witness Ron Nelson demonstrated that the increase in monthly service charges were not fully justified. Mr. Nelson demonstrated that Rocky Mountain's proposal to include demand-related transformer costs within the customer charge was not supported theoretically and that, instead, only customers' specific costs should be collected through the customer charge.

Based on the evidence presented, the Office specifically submits that the single-family basic monthly service charge could be increased but not to exceed $7.

The OCS also examined Rocky Mountain's proposal to remove the last inclining block rate for residential service. And while some witnesses have suggested that the evidence is not compelling -- you can look at Camfield and Wright's hearing testimony -- nevertheless, the OCS decided that it would support the Company's proposal to remove the inclining block rate so long as the basic monthly service customer charge for single-family customers would be limited to a fee of not greater than $7. The OCS believes that incorporation of the Company's proposal without these limitations would result in rates that would be unjustified and inequitable, particularly when considering effects such rates would have on low- and average-use residential customers. We would note that UCE supports the establishment of a working group of stakeholders to consider any new changes to residential rate design.

Also, with respect to the revenue requirements and the issues we've discussed here, possible rate impacts for various adjustments to revenue requirements are clearly shown in OCS Exhibit 3.3S, one of the surrebuttal exhibits attached to Ms. Donna Ramas' testimony. And we'll submit it on that basis. Thank you.

CHAIRMAN LEVAR: Thank you, Mr. Snarr.

Commissioner Allen, do you have any questions for Mr. Moore or Mr. Snarr?

COMMISSIONER ALLEN: No questions. Thank you.

CHAIRMAN LEVAR: Thank you.

Commissioner Clark?

COMMISSIONER CLARK: No questions. Thank you, Mr. Snarr.

CHAIRMAN LEVAR: Okay. Thank you. I have a couple.

Mr. Snarr, I think you probably heard my question to Mr. Russell on modeling for Pryor Mountain. I think you covered your position on that issue in your presentation, but if you'd like to elaborate on that any more, feel free to do so. If you need me to repeat the question I asked earlier, I'd be happy to.

MR. SNARR: Let me -- I recall the question. Let me address it.

We were concerned when we saw the Company make the choice not to go with preapproval on this kind of a project, when it's often been used before.

As we look at the statute that relates to the preapproval process, there's a specific concern in the statute which evidences a public policy of trying to make sure that projects that are brought in for supplying energy are done so at the lowest reasonable cost. And what we determined was, while the Company has the choice -- we don't argue with that -- to not bring a project forward for preapproval, it still must demonstrate prudency. And we believe that part of the consideration of prudency would include some sort of analysis or comparison to other alternative or available energy supplies so that we don't just pursue a project that might be higher than the other ones. That would be inconsistent with prudency.

So, while we haven't suggested a particular model or analysis, we do suggest that the consideration must include whether or not this will bring about energy that could be attributed at a lowest reasonable cost to retail customers, and that that public policy announced in the statute really can't just be totally ignored by not availing themselves of using the preapproval process.

The question still is a part of prudency, and the prudency issues are in this rate case, and we think that it should be addressed.

CHAIRMAN LEVAR: Okay. Thank you, Mr. Snarr. I appreciate that answer.

I'd like to ask you about one other issue, and it's the last one you were speaking about, the proposed customer charge for single- and multi-family homes. And my question is a little bit convoluted, so I'll try to walk you through what I'm asking.

Rocky Mountain Power has proposed a $6 for multi-family and $10 for single-family customer charge, and my understanding is that is intended to incorporate both of those different types of customers' contribution to fixed charges, including line transformers. Now, the Office is proposing reducing the single-family but not reducing the multi-family.

So my question is: Would that, then, require an adjustment to Rocky Mountain Power's proposed energy charge that would apply equally to multi- and single-family? And then the second question is: Would that end up having multi-family residents paying twice for line transformers, once in the $6 customer charge, and then also in the adjusted energy charge that would result from reducing the single-family?

MR. SNARR: You ask some good questions. Let me respond in this way.

We looked at the incorporation of the transformers and found that that tended to raise the initial monthly charges. And we also looked at the impact that might have on some of the residential customers who are using less energy. And we were concerned about that. That's why we zeroed in on that issue.

Our primary concern, however, was with respect to the residential single-family customers who would otherwise see an increased charge up to $10. And so based upon our analysis, we thought that we ought to put the brakes on that at $7 and could support that.

There may need to be some equitable alignment between the multi-family and the single-family charges, and we acknowledge that. Our primary concern was not to see that single-family monthly charge go above $7. And we presented arguments that would support ratcheting that back down, or limiting it to $7.

I understand the nature of your question. We'd probably leave it to the Commission to decide how best to equitably deal with the rationale so that it's fair to both sets of parties. But we can't really tolerate well anything more than $7 for the single-family customers.

CHAIRMAN LEVAR: Thank you. I appreciate that answer. And I don't have any other questions for you, Mr. Snarr, so thank you for your oral argument this morning.

I think with that, we'll take a 10-minute break and then return and move to the Division of Public Utilities. We'll be in a short recess.

(A break was taken from 10:19 a.m. to 10:30 a.m.)

CHAIRMAN LEVAR: We'll be back on the record, and at this point we'll go to the Division of Public Utilities.

MR. JETTER: Good morning, Chairman Levar and Commissioners Clark and Allen. Thank you for this opportunity to provide these closing thoughts on behalf of the Division of Public Utilities.

The Division has presented an array of witnesses on the various topics in this rate case. And we've presented a fairly brief but comprehensive summary of our position on the issues in our closing brief. And I'm not going to try to repeat all of those this morning.

Briefly, I'd like to address a few issues, and starting in the order that's been fairly consistent with the other parties, we'll start with the rate of return.

Rocky Mountain Power has based a lot of their rate of return testimony on this concept that there's uncertainty and volatility in the capital markets and that uncertainty and volatility is causing equity investors to require higher returns on their equity for common stock.

And that concept just hasn't been borne out. In the markets, we're seeing record stock market values, which is a simple mathematical relationship there that dictates that those higher values tend to indicate that investors are, in fact, requiring lower returns. And that's also consistent with what we've seen in other Commission orders on rate of return over the past year. The averages for rate of return are right about 9.5 percent, as has been included and summarized in Division witness Casey Coleman's testimony. And that trend continues on a downward path.

With respect to the typical three models of the capital asset pricing model, the discounted cash flow model, and the risk premium method, Division Witness Coleman used the standard methods of calculating those with the common proxy companies, where appropriate, in those models and the standard risk-free rates of return. And those results remained in the ranges from 7 1/4 to about 9.2 percent. And the Division Witness Coleman made some professionally-based adjustment to that to recommend the 9.25 percent rate of return.

Given the capital structure of Rocky Mountain Power, that return is consistent with what returns have been approved by other commissions throughout the United States in recent months and in the recent year. And what's important to recognize here is that the calculation of those types of models by Ms. Bulkley from Rocky Mountain Power, she makes unusual or nonstandard adjustments or uses models, and all of those have been pointed out in testimony. But those models are inconsistent with the traditional models for those calculations. And the result is, of course, a higher rate of return.

And what I'd really like to focus just the Commission on when they're making this determination is that Division witness Casey Coleman used the standard models in the standard way and recommended a rate of return that is essentially unbiased and is a representation of what a fair rate of return is in the market today. I don't need to go into a lot more detail. Mr. Coleman has explained that pretty thoroughly, both in his testimonies prefiled as well as his testimony live.

I'd like to also address next the question of the production tax credits. And the Division is out on an island here a little bit. We're the only party that has recommended a 10-year schedule on the depreciation of the retired or removed-from-service wind turbine equipment. And the Division continues to believe that this is the most reasonable way to affect the least amount of intergenerational transfer.

There will be some intergenerational inequities no matter how this is broken up. But what we have is a situation where you had wind turbines that were installed approximately 2010-ish. They've been in service for about 10 years out of approximately a 30-year useful life and then are taken out of service and decommissioned primarily for the benefit of a new round of production tax credits. And a secondary justification was that within 10 years, a number of the wind turbine equipment facilities were starting to have higher maintenance and repair costs.

And when we look at the value stream that comes from the decision to do the replacement of those, we have a set of customers that that will run from 2020 out to around 2050. And the customers from 2020 to 2040 would have been paying for depreciation of the prior existing wind turbine equipment through that period and receiving approximately the same amount of fuel-cost free energy over that period as the same customers would with the new equipment.

And so for those customers, the real benefit that they receive from the replacement is the production tax credits. And it seems unreasonable to the Division to make, particularly the customers in the period from 2030 to 2040 -- so it would be the final 10 years of the old equipment and the middle 10 years of the new equipment -- continue to pay the depreciation rates for equipment that was taken out of service in order to receive a new round of production tax credits. And while we recognize that there are -- this is a policy decision for the Commission to make, we think that the most reasonable policy decision to make is to depreciate the out-of-service wind turbine equipment over the 10 years that corresponds with the front-loaded benefit provided by the production tax credit.

And we fully recognize that those out years, years 2040 through 2050 approximately, would receive a benefit that they would not pay -- potentially not pay some or all for. But it's also important to recognize that those customers in years 2040 to 2050 will continue to pay the depreciation rates for the new wind turbine equipment in those years. And so it's not as if they're getting no benefit.

And additionally, if you run out this sort of hypothetical where we take the old equipment out to its final year in 2040, presumably if you replaced it in 2040 with new wind turbine equipment -- and I'm making a lot of assumptions here -- but assuming the costs were roughly the same, when we reach that 2040 mark, the new depreciate rates for new wind equipment that might be installed in 2040 would then be potentially in the same ballpark of what -- the depreciation those customers now will pay in 2040 through 2050. And I hope that all makes sense clearly. And if not, please ask me some questions about it.

The main point being that the Division believes that the primary function and purpose of replacing that wind turbine equipment was a new round of production tax credits, and that that new round of production tax credits would be best matched with the depreciation of those wind turbine equipment that were retired early.

Moving on to, I guess my next issue would be the production tax credits inclusion in the energy balancing account. And this has been a little bit of a contentious issue between the various parties. But the Division firmly believes that the production tax credits are not a power cost, and for that reason that they should not be included in the energy balancing account. And that's been addressed in our post hearing brief.

And the key points that we'd like to sort of reemphasize again today is simply that those aren't power costs, and they don't directly flow with other power costs in the same way. And more importantly, they also don't -- they don't represent the same problem that the energy balancing account was created to resolve. You're not going to see production tax credits double between one rate case and the next. The only variation we'll see is the generation output variation between projection and actuals. Whereas, if you compare that to something like a natural gas fuel cost, natural gas fuel cost has a high amount of variability in the commodity itself, and then there's a secondary variability in the amount that you purchase during that period between rate cases. And at least I believe that that -- there's a fair amount -- let me back up.

The basis for the energy balancing account between rate cases is to allow the utility to stabilize its revenue in respect to those changing fuel costs. And that was primarily for the commodity cost of the fuel more so than the volume used. And for that reason, we don't think that the production tax credit fits well in addition to the fact that it's not an actual power cost.

For those reasons, the production tax credit should be part of base rates without a true-up rather than include it in the energy balancing accounts.

And then I'll briefly address the AMI metering situation. This has been addressed in our brief and in the briefs of other parties. And the core issue here for the Division is we're not objecting to the installation of AMI meters and understand the benefits of those and that they have those benefits and they justify the costs of installing them. The trouble is the timing of those costs.

And under the traditionally used and useful test, there's a little bit more than just being placed physically in service for some part of it. There also needs to be productive delivery of value that justifies the cost of the assets put in service. And, as you've seen in the testimonies, particularly in Rocky Mountain Power Witness Mansfield's Phase I rebuttal testimony, the real value that -- the productive value of those AMI meters is not going to take place until, really, the year

2023. It will be towards the end of 2022. And that's simply too far out and too far beyond the test year to be recoverable in rates now. There has to be some type of a cutoff of how far we project into the future and what amount of utility investor capital becomes used and useful for customers and included in rates.

And under the historic prior to a future test year, it would not have been included in the past base year we've used. And similarly in this case, Rocky Mountain Power chose the future test year that it did, and the AMI metering services that provide the value that justify installing them will not be valuable during the future test year. And it becomes a bit of a slippery slope situation, where if we start allowing future capital expenses beyond the future test year chosen into rates, I'm not sure how far we go. Do we go one year out? Two years out? Five years out? And that becomes a very difficult situation for anyone to analyze whether those individual capital assets that might come online in those out years are offset by other cost savings that we haven't analyzed.

And for those reasons, the AMI meters simply don't meet the use and useful test because their date of service -- and by that service, it's really the productive service in delivering the values that justify the costs of them. Those are simply too far out in time to be included in the test year and should not be included in the rates that are set based on that test year.

And those are the issues that I had intended to address directly in our closing statement that -- mostly to focus on a few parts of our closing brief and our testimony.

I think I can address the Pryor Mountain question asked by Chairman Levar to the other parties. And in addressing that, it is the Division's opinion that the Company has a duty of prudence in its investments. And part of that duty of prudence, making prudent investments, is the lowest cost/lowest risk choice, and a lower cost than what the utility might have otherwise done rather than purchase that project. So the with and without scenario doesn't really give us a full -- a full vision of what the utility might have otherwise done. And we can't say in that scenario that that would be a least cost/least risk approach by simply doing something that's less costly than doing nothing.

And for that reason, it's our opinion that a prudent showing for this type of a facility where the energy isn't necessarily needed, it's a cost saving measure, we should choose the most cost-saving measure.

And in addition, there's a balance of risk which we accept, so it's not necessarily the lowest cost of all options, but the least cost/least risk of the available options to the utility at the time that the decision is made.

And so I think that that answers the question to the best of my ability, which is that we need to consider what alternatives were available in addition to just a go or no go decision on an individual project. And we've expressed some of those concerns in our closing brief regarding how third parties, such as the Division, can really evaluate whether the least cost/least risk decision made without our preapproval processes, which recognizing they're not mandatory.

We don't have perfect 20-20 hindsight in this case. We can't go back and look at what else was available and make a decision. And so we believe it's incumbent on the utility to meet their burden of proof in demonstrating not only that the cost was lower than not doing the project, but also that that cost was lower than the available alternatives to the utility at the time.

And that concludes my closing statement. I'm happy to answer questions from the Commissioners.

CHAIRMAN LEVAR: Thank you, Mr. Jetter.

I'll go to Commissioner Clark first.

Do you have any questions for Mr. Jetter?

COMMISSIONER CLARK: I have no questions. Thank you, Mr. Jetter.

CHAIRMAN LEVAR: Thank you.

Commissioner Allen?

COMMISSIONER ALLEN: Thank you. No questions from me, either.

CHAIRMAN LEVAR: Okay. Thank you.

I have a few.

First, just from a legal basis, obviously we have to struggle with what does the word "useful" mean in the context of "used and useful," particularly on the AMI issue. And 1 and 2 of the starting point is it means something in between the word "used" because it has to mean something different from "used." And on the other extreme, it could be cost-effective. Does it have to be cost-effective to be useful, or at least within the test period issue we're talking about?

How would you suggest we define the word "useful"? Does it mean that something is cost-effective? And if it does, why do we have a different word than cost-effective?

MR. JETTER: I can't say why it's a different word from "cost-effective" necessarily. I think that I would describe it as something like "used" and "prudent."

And the reason I think that is, is that you can have a facility that -- maybe the AMI meter actually is a great example, where it could be partially used but used in such a way that would not justify the cost of installing it. And in that case, at least in my view, it doesn't meet the principle of "used and useful," that it's used and useful in such a way that justifies the cost included in rates.

Customers are going to be paying rates, and what they should be paying for is utility investment that is delivering the value to the customers that is typically equal to or greater than the value that the customers are compensating the utility for. And so in that respect, I think that that translates to the capital investment by the utility once it starts to be paid for by customers. The customers need to be receiving the benefit for which they're paying. And that would require, I guess in my view, the utility to be in at least in enough service to justify the cost that they're paying for.

CHAIRMAN LEVAR: Okay. Thank you.

MR. JETTER: That's a long answer. I don't know if that answered your question.

CHAIRMAN LEVAR: It gave me -- I think I can get it on that.

In your view, do we have enough in the record to make any kind of estimate of how much of the AMI project would be at least used, putting aside the useful portion, but would be in operation and used during each month of the test year? Can we make a reasonable estimate of that from what we have in the record?

MR. JETTER: I don't know on a monthly basis. I believe there is testimony from Mr. Mansfield that approximately 34,000 meters will be, I guess, operational and used in the function of metering electricity.

CHAIRMAN LEVAR: That's for the entire test year, right?

MR. JETTER: Yeah. And I'm not sure that that's providing a lot of meaningful value over the meters that were there in the prior time, the AMR meters that would be replaced during the test year. However, that's -- my understanding is 34,000 is something along the lines of 20 percent of the total number of AMI meters that will be installed.

I don't know how to estimate a used or useful sort of quantitative value for the other components of the system, so the software and the antennas and those components of the system which are a significant portion of the cost. And it's been testified that, I believe -- I'm recalling from memory -- somewhere in the range of 80 percent of those may be completed during the test year, if my memory is correct of Mr. Mansfield's testimony.

I don't know how to quantify a portion of that that's useful if they're not fully functioning. I don't know how to give an answer for that portion of the costs.

CHAIRMAN LEVAR: Thank you. I just want to ask a couple more questions on production tax credits. The first question is maybe an intuitive question.

But is there any potential that production tax credits could ever exceed projections by any meaningful amount in a given year? Or are the projections pretty much the cap of where they could be, and we're only looking at whether they might be lower in a particular year?

MR. JETTER: They certainly could exceed the projection by some amount. I think it's unlikely that they would exceed it by a high amount. And the reason for that is that the variation is going to be primarily based on wind speeds and timing. And I think the expectation is that is wind turbines will operate at full capacity every hour that that wind is available to generate.

And so I think the expectation is that there will be some variation from the projections, but it won't be more than a few percentage up or down in a given year, with the exception of an unplanned outage.

CHAIRMAN LEVAR: Thank you. And I recognize that might have been a better question to ask during the evidentiary hearing of your witness than ask you in closing arguments, so I apologize for that.

My next question, which is more of a -- relates more to your closing statement is in terms of whether they should go into the EBA as a net power cost. How would you describe the similarities and the distinctions between production tax credits and wheeling revenue?

MR. JETTER: I suppose I would say that wheeling revenue is probably more similar to production tax credits than natural gas prices as a commodity. Wheeling revenue values are typically set mostly out of time. And I suppose the closest thing I could differentiate those two is that wheeling revenue is part of a direct power cost to deliver energy to customers. And a production tax credit is a tax credit that's separate that is related to the generation output of the wind turbines, but it's not part of a power cost in a traditional power cost sense.

CHAIRMAN LEVAR: Okay. Thank you. That's --

MR. JETTER: I recognize they do have some similarities.

CHAIRMAN LEVAR: Okay. Well, thank you. I appreciate that. I don't have any other questions for you, so thank you for your time this morning, Mr. Jetter.

MR. JETTER: Thank you, Mr. Chairman.

CHAIRMAN LEVAR: And with that, we will go to Rocky Mountain Power.

MR. MOSCON: Thank you, Mr. Chairman. Just since we haven't spoken, I'm assuming that you can hear and see us and that there's not a significant echo. So please let me know if there is.

Before I begin, the Commission asked a question about whether a specific figure was confidential. So before I get into my materials, I'd like to answer that for the Commission.

The dollar amount that was put on the screen from Dr. Zenger's testimony was actually an estimate of what the Company thought the cost would be in June of 2019. Accordingly, because now we have the actual number, which I'll note is significantly less, the actual number is confidential, but that estimate is not confidential. So, I don't know if that fully answers your question, but that specific figure as now a historic estimate is not confidential.

So with that, I'm going to proceed into my closing. And I -- just because of the amount of material to cover, I thought it would be helpful, if the

Commission will allow me, to do a presentation that could share some of the exhibits and some quotes from testimony to answer the questions that have been brought up today, if that's okay.

Let's see. I want to share my entire screen. What am I doing here? I'm going to get some help already.

I'm going to assume unless someone goes off mute and tells me otherwise that this is now being shared on all screens as I move forward.

Before I get going into these materials, I'd like to do two things. First, during some of the arguments that we just heard, including from, I think counsel for the OCS, a point was made that there was a bit of disappointment that the Company hadn't briefed every single issue. And I just would like to point out for my client that just due to the limitations that the Company, having to respond to all parties but having the same page limitation, really did not have an ability to do that. But the Commission should certainly know that the Company views its case as being the testimony, not in the briefs, not even what I'm about to say. So we do not concede anything or by virtue of the fact that it -- just fitting in with page limitations or time constraints for closing, if something is not specifically highlighted that that means the Company concedes a point.

And I'm going to begin, I think, with cost of capital.

But before I do, I want to echo and recall for the Commission the testimony of the Company's CEO, Mr. Hoogeveen, who noted that the Company takes pride in the fact that it has customers that are able to enjoy low energy costs and the fact that the Company has not filed a rate case in six years, and notes that even if all of the increases sought here were allowed -- and we recognize they may not be -- but even if that were to be the case, that Mr. Hoogeveen pointed out that our customers would still be both below national and local averages in comparison.

And I just want that to be in the back of the Commissioners' minds that the Company does not ask for increases lightly or without a lot of thought. It's not something that they just take carelessly. And I hope that will stick in the back of everyone's mind as we proceed forward.

First topic is cost of capital and specific return on equity. I want to call attention to cases that all parties have told the Commission are determinative in this phase of the case, Hope and Bluefield. But no one, and I have to concede not even my client in our briefs, gave the Commission any context for what that means. So I'd like to give you my thought on that.

This quote from the Bluefield case states that, "The ascertainment of that value" -- and "that value," by the way is the ROE, "is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts."

The reason I highlight this is what I see going on as a little bit of a battle of the experts about, You didn't, you know, differentiate between the fed rate the same way, and your forward-looking DCM model is not as good as my kappa model. And I'm not trying to suggest the Commission should not view that type of evidence. Certainly it should. But I'm hopeful that the Commission will, at the end of the day, step back and make a judgment based on a totality of the circumstances, totality of the market, what's in the best interest of the customers, taking clues from what is happening across the country, rather than simply being led to believe by any parties that you must follow the dictates of a specific model and being caught in the trap of saying, Well, whose model is best?

The first topic I want to get into in depth is market conditions. All parties agree that market conditions impact the appropriate rate of return. There's no question but that the market has changed substantially between 2014 and 2020. And the way it's changed is market conditions are far more volatile now, and are expected to stay that way into 2021.

The reason I'm pointing this out is this Commission in its recent Dominion order noted that it's an appropriate analysis to make in this setting to look at the utility's last rate case when the last ROE was set, look at what's being requested now and compare what was the market like then when we set that level, and what's the market like now that we're being asked to modify that level?

So one of the topics was volatility. And this, which is taken from Ms. Bulkley's testimony, shows -- this line here where the last rate case was, showing that unquestionably volatility is at a significantly higher level now than it was at the Company's last rate case. And, importantly, this slide, which was also in testimony, indicates that going into the future that that volatility is expected to continue through 2021, meaning it's not just volatile now in the spring and summer of 2020, but that the indexes that all experts rely on predict volatility to continue well into the test period.

The utility industry has underperformed and has not recovered. And it is expected to struggle into the future. Now, this is a point that we've heard a couple of times this morning in closing arguments of the different parties where we've heard, Hey, look, the market has returned. I don't know why they're making an issue of this because the stock market has bounced back. We're now at record levels.

But what that ignores was this Cross Exhibit 7, and the dashed line at the top is showing the actual S&P 500, which we can see here did take a dive in the spring when we had the lockdowns. And it's been coming back up.

But this line, which is the utilities line, has essentially remained flat through this level that it reached back in May compared to the overall S&P which has outpaced it now relatively significantly.

Now, what does that mean? The reason that's important is it shows that historic views of utilities as a safe haven for investors has gone away. If investors see that the stock market generally is performing better than utilities, investors are not going to want to sink their dollars into utilities. Utilities need a higher rate of return to attract those dollars because, historically, it was this, where utilities were outperforming the market, so investors wanted to put their money in utilities. That has changed, and it is expected to continue changed going into the future.

Now, the Duff & Phelps report is a document that we discussed for quite a while at the hearing. It was part of the cross-examination of DPU witness, Mr. Coleman. It was relied upon them in coming up with their calculations. And I want to highlight what we had conceded to us during cross as to why the DPU's value should be rejected by this Commission -- by "values," I mean the ROE.

The report that they base their analysis on supports an increased equity premium based on risk, and that's the thing that I've been talking about. And we just heard in argument that, Look, that really -- all this volatility and risk doesn't mean you should raise the ROE. That's not what the market is showing us. But the Duff & Phelps report that their expert witness relies upon completely says that you should specifically.

Furthermore, that report shows the same market volatility that the Company's witness discusses while the DPU did not adjust for market volatility.

Finally, the DPU did not change their recommendation despite continued uncertainty going into the future. Now, to show that what I'm saying is true, this, you may recall, was an exhibit, and it highlighted volatility and uncertainty. And Dr. Coleman had conceded that what the -- or excuse me. I shouldn't say Doctor. Mr. Coleman conceded that as both uncertainty and volatility rise, the risk premium rises. And what the risk premium, I'll remind everyone is, is the amount that you would put on top of whatever your underlying data would value their ROE to be.

This was in the testimony where here, at the conclusion, "That's what it's showing, yes," where Dr. Coleman -- I apologize. I keep saying that -- Mr. Coleman conceded that Duff & Phelps indicated that there should be a premium awarded for increased uncertainty and volatility.

Now, the data from Duff & Phelps interestingly showed the same volatility that Company Witness Bulkley identified. So it's not that Ms. Bulkley is coming up with these unusual things that no one else in the industry look at or relies upon, these slides taken directly from the Duff & Phelps report that the DPU used identify literally the same numbers that Ms. Bulkley identified in her testimony.

Same with uncertainty. The same index was used by Duff & Phelps that Ms. Bulkley was using. So again, it is incorrect to say that she is doing something that other experts in the field would not consider.

The conclusion on the market conditions that the

Commission should take is that the cost of equity has increased, it has not decreased. Investors are going to expect higher returns to account for market volatility and risk. Now, this is common sense. If there is more risk in the utility sector than there is in the overall S&P market -- and we've shown slides indicating that is the case -- they're not going to want to put their money, their investments in the utilities unless the return is a reward for that risk. And because the volatility and uncertainty has increased compared to when the Company's last rate case in 2014 was analyzed, that tells us as a starting position that the return on equity should be higher and not lower than it was in 2014.

So let's talk specifically about authorized ROEs for vertically integrated utilities. Now, Company Witness Bulkley and Mr. Chriss both showed an identical median authorized ROE of 9.73 from the time frame of 2017 to 2020. I just heard -- I don't remember which entity said that the Company was relying on stale data. And I'd like to emphasize this is as current data as was possible by the time that the hearing was had.

The vast majority of decisions for integrated utilities, 47 out of 63, or 75 percent of decisions for ROEs during this time period were between 9.5 and 10.5, indicating that 25 percent is dragging down the average, but the bulk of the decisions have 9.5 as the low going up to 10.5.

The Company's proposed ROE of 9.8 is on the lower half of that range; meaning, if you were to slice this in the middle, you'd end up right at 10.0 on the nose. And the Company's modified proposal of 9.8, therefore, is on the lower half of this 3/4 majority of decisions from the recent time frame of available data.

This figure highlights what I was just pointing out that came from Ms. Bulkley. This is a very telling exhibit that I hope the Commission will look at as it makes its decision. This is Ms. Bulkley's recommendation of 9.8. These dots are all of the decided vertically integrated electric company decisions from beginning of 2018 through the date of the hearing. And there's a spread that accounts for different issues.

The OCS recommendation here is a complete outlier, and Mr. Coleman's recommendation here is an outlier, all of them being well in the bottom. There's only one decision out of all of them that is worse than the -- meaning lower than Dr. Woolridge recommends. There are only two decisions lower than the rate proposed by Mr. Coleman; whereas, Ms. Bulkley's recommendation is right in the middle of all of those decisions.

When we heard from Dr. Woolridge, he conceded what I just said was true. When we pointed out to him that his recommendation was well below the typical authorized return, he had to concede that, in fact, that correct. And more importantly, he pointed out that in all of the cases that he's testified in -- and we're going to look at a slide here in a minute -- that he never, at least going back a number of years, proposed a single ROE at above 9.0 percent. This is what I'm talking about.

So this goes all the way back to 2012. This dotted line are the proposed ROEs of Dr. Woolridge. The line, and it's kind of hard to see here, but this line here is the results in the cases that Dr. Woolridge was the witness in. And this is the average authorized ROE for all cases for that month and year.

What this shows us is that no Commission from 2012 through this time at 2020 in any type of case has ever accepted the recommendation by Dr. Woolridge, and his numbers are typically a full point and a half below the actual decided ROE by the Commission. Again, this goes to the point that I'm saying that the Commission should look at a reasonable conclusion.

Significantly, the Office does not rely on its own ROE calculated range. And the Office could not reconcile the market data and volatility with their recommendation. So the Commission should simply conclude that that is not reasonable or reliable.

Similarly, Mr. Coleman did not use the range that he calculated. He had to come up with a subjective adjustment and admitted that the ROEs he used were not limited to vertically-integrated utilities and conceded that he did not exclude distribution-only utilities or litigated cases.

So I wanted to put this in to simply call out something that was in the briefs and a little bit here in argument, which is that the Company is treating the interest factor incorrectly. There was an argument made that the Company is justifying ROE calculations by arguing that interest rates will rise, but arguing that they stay low in pension to justify its position. This is untrue. The reason is, it's not the same interest rate. And this is an issue that's in, you know, Ms. Kobliha's area.

But essentially, the interest rate in the pension expense is a historic interest rate that is triggered by GAP and IRS rules at a certain time that an expense occurs, and it is looking in the reverse; whereas the interest that is being calculated for ROE purposes is a forward-looking interest rate asking, What interest do we need to attract investors? So it's a complete different calculation with different drivers.

The next claim that we heard is that -- from the post hearing brief of the Office that the Company is ignoring the federal funds rate for purposes of ROE. And the statement was just made that RMP does not dispute this, but argues that changes in the federal funds rates do not affect long-term interest rates, and therefore, do not argue for lower ROEs. So the criticism is the Company should not be believed because we're not changing our recommendation based on this low federal reserve that we just heard referenced also by the Division.

However, at the hearing, the intervention witnesses agreed with what the Company is doing. This quote came from Dr. Woolridge: "The fed -- the overnight fed funds rate doesn't relate to ROEs ... [N]either Ms. Bulkley or myself look at the feds fund rates and use it in any way to estimate an ROE."

So the criticism that was just levied against the Company for not -- you know, Hey, the interest rates are now at zero, and they're going to be that way through 2023, all parties agree, at least their experts do, that that is not something you look at in estimating an ROE.

We don't need to take a lot of time on this. This was simply the authorized ROEs relied on by the Division. But as the Commission will recall, it included not just vertically-integrated utilities, but limited issue rider plans, distribution-only companies, et cetera. And in their brief, they spend a lot of time talking about, well, the real average is 9 1/2. But it's only 9 1/2 when you include states like Maine or Vermont that we talked about that had decisions that were based on a formula on a settlement, not on a litigated result. The true mean of litigated cases from this time frame was 9.73 percent.

The Company's ROE analysis incorporates current market data. It applies modeling procedures approved, used by decades in commissions across the country. Contrary to the arguments that have just been made, it reflects market conditions and increased volatility. And Ms. Bulkley's ROE range falls squarely within the range of authorized returns for similar utilities across the country during the relevant time frame. In fact, the Company, by lowering its request to 9.8, is actually seeking a lower return than is justified by data.

This, again, before we move on to the next topic, I hope stays with the Commission. And going back to the Hope and Bluefield cases. When you see this type of spread, and you see that this is what commissions across the country are determining is necessary to attract investment for the benefit of customers in their states and jurisdictions, the Commission should reject argumentation that the returns should be put in such a low bracket. That would be a completely outlier position that would not be beneficial for Utah customers.

I want to move very briefly to capital structure. This is an issue of the OCS. The Company's position is that the common equity percentage has consistently been above 51.49 percent for the last three years. The proposal by the Office is below actual. And we have this quote: "The Company's proposal is consistent with the average of the five quarter-ending balances spanning the test period." The Commission has previously approved this approach.

So the Company's approach is not only following Commission precedent, it is the actual thing. It is not just an estimated or hypothetical number that is being developed by an expert.

Finally, Dr. Woolridge's recommendation is based on a proxy data group of holding companies and is not based on utility operating companies themselves. And it has an improper debt ratio that applies to non-utility activities.

The proposed rate structure that the Office asked the Commission to adopt is not reasonable. The Company's proposal is well within the actual calculated range. Dr. Woolridge did not provide a calculated range, he simply picked a mid point between the Company's proposed equity position and the average of his proxy group. That just kind of randomly picking an average between two, or median point, is not a way of saying, This is what the range should be based on data.

Finally, the Company has shown in testimony that it has significant capital spending requirements. It has impacts of the Tax Cuts and Jobs Act. Both of these the witness pointed out necessitate the equity percentage of 53.67 percent. There was no testimony by other parties of how we can maintain our credit ratings if we go below that.

There's been an argument that we already have this rating, but there's been no evidence put forward about whether we would be able to maintain that rating if we went to such an artificially low capital structure.

Conclusion: Unopposed by any party besides the Office, the Company's rate structure of 53.6 -- and it should be 7 because there's .01 percent of, I think, preferred stock -- the Company's position is based on actual data, is necessary, fair, and reasonable.

I'm assuming -- I'm just going to go through the entire presentation, but if the Commission would want to stop and ask questions, I'm assuming it will do so.

Otherwise, I'm just going to move into revenue requirement, unless somebody interrupts me otherwise.

One of the main topics that we just had addressed in argument or certain questions was on inclusion of PTCs in the EBA. The Company's proposal is that net power cost forecast produced by the GRID model forecasts wind generation volumes, so it is a forecast.

The PTC dollar estimate is calculated directly from a model, the same model that's used for all of the other net power costs that go into the EBA.

It's a better fit to include PTCs with the variable net power costs in the EBA instead of in base revenues because it has the same likelihood of volatility or being higher or lower than projection, as net power costs do.

And it would allow full benefits to be provided annually and better match costs with benefits.

The DPU has opposed it, saying that it's not called out for in the statute. However, they have conceded that the statute's list is not exclusive. I think we just heard a candid confession that the PTCs, in fact, do share a common relationship with power costs and that they vary based on generation output. And the distinctions are unavailing.

PTCs vary in volume. This was a question that the Chair just asked a short time ago: Is there any significant variation with PTCs? And the answer is they vary in volume and total value in the same way that -- just because they're based on production. Production from these facilities varies. Is it going to be very windy? Not very windy? A medium amount of wind? And so these production credits are going to vary.

It's interesting that the Chair also had the same question about wheeling revenue. Wheeling revenue is not a cost. It is still included in the EBA. And so we know that the legislature did not intend to limit what goes into the EBA to simply hard costs. And PTCs are going to vary year to year, just like fuel variations occur. And so it just makes sense.

We'll finally note that other balancing accounts exist for similar items. They're a balancing account for recs and other items that are not hard costs. So it makes absolute sense. I think there's a concession that it made sense. There's only a question about is it statutorily allowed?

Only thing on the statute I will note -- and I apologize I don't have a slide for it. This wasn't in a brief. I'm just kind of responding on the fly to the comment that we just heard -- is that the energy balancing account statute Section 1 is where the costs are discussed.

But if you go down to Section 4, it points out, which is kind of intuitive, that revenues also belong in the balancing account because you can't just have costs in there, you have to have revenues. It doesn't call out all of the revenues, so there is not any kind of subdetermination of the types of revenues. But to the extent that the Commission wants to think of it this way: A tax credit is tantamount to a revenue; meaning, you would otherwise need revenue to pay a tax that you were, instead, getting a credit for. And so I would argue in addition to other similarities that we've seen here, that Section 4 of that statute that allows for revenues to be included would also allow for this type of inclusion of PTCs in the EBA. Customers are going to get exact benefits and costs. It is not about shifting risks.

Okay. Now, let's turn to the next big item, which is Pryor Mountain. This is, I think, really the reason we wanted to undertake this exercise, which I have not seen anyone really address what the statute is and what the standard is that the Commission must apply to the Pryor Mountain decision.

The general rate case standard, which is not the preapproval standard, is a prudence determination, and it is important because all these words that we keep hearing thrown about, "least cost," et cetera, do not appear in the statute.

Rather, the standard of review of prudence is that it is just and reasonable, and that it was reasonable judged at the time that the action was taken based on what the utility knew or reasonably should have known at the time the action was taken. So this, not, Is it the absolute lowest cost? Have they proven it's the lowest cost? That is not the standard. The standard is prudence, and is it just and reasonable?

I think it's important to be clear about the Pryor Mountain opportunity. It was identified in October 2018. It was already, at that point, a late-stage development. It already had an executed Large Generation Interconnection Agreement.

An agreement to acquire development rights was not executed until May of 2019, and the Company was, at that point, not obligated to proceed if it wasn't economic.

The Company entered into an agreement to sell the recs generated by the project. That is now a contractual agreement. It's not a proposal or a forward-looking forecast. It's an actual contract.

The ability to acquire the generation equipment from the affiliate, Berkshire Hathaway Energy Renewables, is important, and I think we need to focus on a couple of things.

The safe harbor equipment to qualify the project for full PTC eligibility could not have been obtained without having an affiliate transaction. And this is an IRS rule because in the IRS -- you had to start construction by 2016 to get this benefit. This opportunity is not identified until 2018. But IRS rules allow transactions between affiliates. So that if a turbine or a generation piece is qualified for PTC credit, it can be transferred between facilities -- or, excuse me, subsidiaries and still retain that PTC benefit. If you have eligible generation units of 5 percent of your project, it qualifies the entire project for the PTC credits.

So, there's been a lot of discussion about, Gee, was this just really done for the benefit of the affiliate? But that just shows that this issue hasn't been thought through. The only way that you can get the significant PTC value is at this date and time, meaning post 2016, to have an affiliate transaction to get the safe harbor ability to transfer those credits.

Furthermore, these facilities -- these generation pieces were in Colorado. That meant that there was less risk in having to transport them across international boundaries or all the way across the country. They were very close to where they were going to be installed, so there was a low-risk opportunity.

The Company did have a competitive bid for all the follow-on equipment that it got outside of the amount necessary to get the PTC eligibility and for the construction contracts.

The economic analysis that Mr. Link describes in his testimony to justify it is the same methodology that was both used and approved in the EV2020 docket, so we don't have a concern that the Company is just using some new analysis to its benefit here. It's the same analysis that has been used and approved.

Finally -- and this was a point that where Dr. Zenger agreed that, Okay, I didn't know that. That removes my concern -- is, in addition to all of this, the Company itself had to do an internal review and get its parent company to approve this purchase, showing the economic benefits and showing that there were risk mitigation strategies.

This is a slide from Mr. Link's testimony. And I think it's important to focus on this for a minute because there's been a lot of talk or argument about the fact that, Hey, we don't know if customers are really going to get a benefit here.

Again, the statute showed us that the Commission should say, At the time the opportunity was presented, did the Company make an appropriate decision? And this is what the economic analysis showed us.

The parentheticals are benefits to customers in millions of dollars. And the one item here is a cost. So we have a range of possibly $82 million beneficial to customers weighing against a risk of possibly only 1 million -- or excuse me, $82 million benefit that you're weighing against possibly only 1 million of cost. And this 1 million of cost comes, again, in the low natural gas price, low to no carbon cost scenario, which the Company said is the most conservative, least likely scenario.

So the question the Commission needs to ask itself is: Presented with this analysis that was done in a method that's been approved previously, does it make sense to say that three of the four possible scenarios show benefits to our customers, possibly significant benefits to our customers? There is only one that shows risk, and that risk is small. The risk-benefit analysis would show it was prudent to make this decision. Furthermore, as we've heard already in testimony, there was a need that needed to be met.

So I want to address very quickly, because I think there was a bit of a concession in closing of the idea of, Was preapproval required? And I think it's now been conceded it is not required, it is something that the Company may do. But the fact that it chose not to do something -- and again, in a time-limited circumstance -- that is optional is not something that this Commission should weigh against the Company.

I want to address this argument that this is not the least cost/least risk decision to be made. First, again, by putting this slide up here, I don't want the Commission to think we are conceding this is the standard. That is the standard for the preapproval statute. This is not the standard for a general prudence review.

But even if it were, absolutely the Company put on testimony and met its burden to show that this was the least cost/least risk path that the Company could take.

At the hearing, not just in direct testimony, but at the hearing subject to cross-examination, Mr. Link stated, "The Pryor Mountain economic analysis shows that system costs are expected to be lower than otherwise would be the case if the Company did not build that wind facility. The analysis shows that Pryor Mountain is a lower cost than other resource alternates, which includes energy efficiency, demand response, other generating assets of all different types, technologies, and the potential for FOTs," or front office transactions.

We today heard speculation that the Company only did an analysis of this first half, that it's better doing it than it is not doing it, but that there was no analysis comparing it to other ways of meeting the capacity need. And that is incorrect.

Here, Mr. Link is expressly stating that it was compared to all of these other possible ways to meet the need. And it's not in this slide, but my colleague handed me a transcript from the hearing in which there are, if the Commission is interested, at least six different pages of when Mr. Link was on the stand when this second half of this analysis was discussed, showing analysis of other energy response items, other ways of filling the capacity need, and how Pryor Mountain was, according to their analysis, the best choice.

Again, on the affiliate transaction equipment, Mr. Van Engelenhoven testified that the Company had an opportunity to acquire these components that were already manufactured at the affiliate's cost, which was the competitive market price at their time of purchase in 2016.

So, the point is that they're saying, We haven't proven that we are at the -- you know, that this was at cost or better, and that this is -- you know, is it market, or is it better than market?

Go back to the point that was made about the IRS. There is no market, per se, for safe harbor turbines because you can't transfer them other than through an affiliate. If you went out on the market and just bought these turbines from another entity, you would lose the safe harbor provision.

We know that when the renewables entity purchased these in 2016 that it was bought at market price. And we know from testimony of Mr. Van Engelenhoven that there was no mark-up, that these were bought at cost. So the Company did meet its burden to show that these were at market or better because, again, the only market is between affiliates. And there was no mark-up whatsoever. It was bought at the affiliate's cost.

Again, I don't want to take the time to read this, but there were additional places in the hearing in testimony describing how there was no ability to go elsewhere. There was a lot of market pressure. And explaining how the Company considered the location, the storage, et cetera, the reduction of risk of going forward with this affiliate transaction.

I want to turn to cost overruns. There's been some, I guess, statement that, Well, maybe it was a good idea at the time, but because of the pandemic there are now cost overruns, so that may be a reason why the Commission shouldn't allow this. And it is true that the Company received notices from suppliers and contractors that, due to the pandemic that caused interruption to the global supply chain, that they would have overruns.

However, what has been established in this testimony is that the project is beneficial to customers even with or regardless of those overruns. Significantly, there's no evidence from any party that any of the overruns were caused by the Company or that the pandemic should have been foreseen in spring 2019 when this was acquired.

And, furthermore, the Company has taken mitigation efforts here to over -- excuse me -- taken actions to mitigate these cost overruns. Again, go back to -- mentally, I won't click us back there -- but to the statute that says when we're looking at prudence, we're looking at the time the decision was made.

So the question for the Commission is: At the time that the decision was made, was Pryor Mountain a prudent decision? Not, Should we penalize the Company after the fact because the COVID pandemic interrupted supply chains that raised some prices?

I want to address the QF pricing raised by UAE. This is, I'm going to note, a novel argument because Pryor Mountain is going to be like every other generation resource of the Company. It is a utility-owned generation resource. It's not different than a gas-powered plant or a coal fired power plant. It is a generation resource owned by a utility. There is no precedent anywhere, no case, no reason, no rationale for treating this one owned generation resource like a QF while treating others as typical plants in service.

The point that the UAE appears to be making is, hey, back when this was being looked at by a potential QF developer, you gave an indicative price, and the price that customers are going to have to pay now is higher. And so the UAE doesn't like that, and they say make the Company stick to the proposed indicative price.

But as Mr. Link testified, that qualifying developer did not execute a contract at that price because they, you know, knew, doing the math, that it wouldn't and couldn't pencil out by the time it actually came around or time to develop the project.

The Commission may recall that during the hearing this is when we had a bit of a, I think, hoped to be a smoking-gun moment where we went into confidential session, and Mr. Higgins said that he was aware of other projects at that same price that had been contracted. But what was conceded on cross, or at least he, I think said he couldn't refute the point, was that those contracts had all been canceled by the developer at their discretion as they're able to do so. So that, importantly, no other project has been developed at the price that the UAE suggested control in this matter.

So not only is there no precedent for treating a Company-owned resource like a QF, but the price that they want to use for the QF price is not a valid QF price point anyway because no developer has been able to bring to market a generation resource at that price point. So it's unfair to say, well, customers are now going to pay more than what that predicted indicative price point was because that was a price that was too low to put a resource online in 2019, 2020, 2021.

I want to move to the two-step rate increase. Delayed portions of the TB Flats in Pryor Mountain, the Company is asking that the annualized revenue requirement align with the in-service dates in 2021. I want to emphasize that the Company is not for a separate test period. And the reason I say that is a test period is when a commission looks at the time frame in which costs must be incurred, and we're only going to put into base the costs that are actually incurred or believed that will be incurred during that test period.

Significantly, all of the costs for Pryor Mountain and TB Flats that are at issue here will have been incurred during the approved test period. So we are not asking for an exception to the test period because all of the costs that the Company is seeking to put into base will have been incurred during the test period.

The Company's proposal aligns cost recovery with the net power cost and the PTC benefits. Absent a two-step rate increase, the combined projects would qualify as a major plant addition in 2021. A two-step rate increase is the same as a cost recovery for a major plant addition under the code.

I want the Commission to have some ease that statutorily the legislature has given it the ability to do just this, where it has indicated that the Commission can approve any method of rate regulation or any mechanism that it thinks is going to be just and reasonable or in customers' best interest.

And finally, and there's only one highlight here, the Commission has previously approved step-rate increases in the past. I've put in this slide one docket, but I will note that in the testimony of Ms. Steward -- this was her rebuttal testimony on page 11, lines 213 and down, and then at the bottom of page 12 if the Commission cares to look -- she recites various examples of times when the Company has had multiple-step rate increases in the past. So this is not a novel idea. This is something that has happened in the past that the statute allows the Commission to do.

Lake Side outage. Very quickly on this, there is an argument in the briefs that the Company has failed to prove that the costs of the outage were prudent and that's because the root cause analysis didn't conclude what caused the outage. No one knows exactly what happened. Did something break? What happened?

And the Office's position is that well, in that case, that goes to the shareholder, that the customers are not going to pay for that.

The argument that the Office puts forward has been rejected by this Commission previously. This is the March 4, 2020, order on Blundell Unit 2. And it was the exact same scenario, where there was an inability of the root cause investigators to determine what caused the outage.

And so instead, the Commission looked at whether there was evidence that the Company had handled the situation improperly. Did it, you know, mishandle the installation of the facilities? Did it not maintain the equipment? Did it somehow fail in its job? And because there was no evidence that it had not done so -- and, in fact, the evidence was that it had acted prudently -- the Commission indicated that it would then, because the Company acted prudently in dealing with the equipment, it was going to allow the costs for the outage. It is exactly the same scenario here today, and the Office's argument has already been rejected once.

Let's turn to pension costs. There's two things that we want to talk about. The settlement losses. No party is disputing that the Company is entitled to recover these losses, the question is how.

The Company is recommending that this expenditure be recovered like any other similar expenditure through rates. Or alternatively, the Company has said it proposes a balancing account, an account that would true-up annually the difference between the actual and expected level of net periodic benefit cost of the Company's pension and other post retirement plans, including losses and any other curtailment gains or losses.

And Office and UAE's proposal to amortize settlement losses and delay recovery over 20 years unnecessarily, unduly, and without good reason prejudices the Company because it simply delays recovery of costs that the Company will actually incur during the test period. And again there's no dispute that the Company is going to actually incur these costs during the test period.

So prepaid pension expense, the problem, as Ms. Kobliha explained, this also is something that I want to harken back to a comment made during a closing argument of the Office, where there was an indication that this is this dramatic departure, and why is the Company doing this? This is not the way we've done it before. This is important for the Commission to understand.

Changes in ERISA, including the Pension Protection Act, changes in law are what now require the Company to have these increased contributions that cannot be immediately expensed under accounting rules. So it is incorrect for the Office to contend that we have not explained why we are doing this. Those laws took place earlier in the 2000s. The Company in its 2014 rate case put the same pension treatment in the case. The case was settled, so the Commission did not have to decide the issue.

But this is not a new and novel theory that the Company is coming up with in 2020. It is coming up because of a change in law, and the Company has previously in its last rate case indicated that it now has these costs that it has to account for.

The legal requirement of the Company results in the Company having to finance contributions, just as it finances other rate-based items but without the ability to recover the financing costs associated with the net prepaid expense. That is all the Company is seeking to recover.

So the solution is including its cumulative net prepaid and other post-retirement assets in rate base based on the 13-month average of its net prepaid pension and other post-retirement assets, earning a return equal to the Company's weighted average cost of capital.

The Company's proposal is just and reasonable, which is the standard for prudence.

The Company is required by law to make these contributions. The resulting contribution is the same as any other rate base items that the Company must finance for which it would be allowed recovery.

And the Company's contribution benefits customers because the return on plan assets reduce future pension costs, it allows for favorable tax deductions, and it avoids premium increases.

Going to turn to, very quickly, Cholla and see what costs -- unrecovered materials and supply costs are recoverable. This is not a Utah case, but I just, for the Commission's sake, want to call out this case which has held a utility is permitted to amortize and recover amounts for unused materials and supplies necessary for the operation of a plant that is scheduled to be decommissioned. So again, there is precedent for what the Company is asking for.

The M&S costs at issue consist of supplies purchased to maintain and operate the plant prior to the decision being made that it was more profitable to close the plant. And therefore, because the supplies were prudently incurred in the first instance, and now because the Company is making the prudent decision to close Cholla, it should be allowed to recover those costs under this precedent for doing so.

CWIP. Unexpensed CWIP costs remaining at the time of the plant closure are unrecoverable. I won't read all of these, but again, there is ample precedent for this, saying that unexpensed CWIP costs when a plant closes should be recoverable.

And furthermore, I highlight this bottom quote here saying that if you don't allow this recovery, you're going to incent your utilities to not -- you know, they're going to be nervous about it. They're not going to keep their plants safe because they're going to keep things at the bare bones.

In this slide, before we turn from revenue requirement to the final topic of cost of service, I want to simply note that there were many other items that were not addressed in our brief or that I haven't covered here simply because of time and page limitations. But again, it's not because the Company does not think that they're important.

I'm going to call out a couple of things that were discussed in other parties' closing arguments. So, for instance, the retired wind repowering assets. The Company should recover for these assets just as it would for any other regulatory asset. Just because there is a favorable outcome to some customers by forcing the Company to amortize it over a long period of time does not mean that it is the fair or equitable result that the Commission should do.

Property tax, the actual property tax estimate should be used, not a multi-year average. There was good cross-examination on this point that the average is incorrect because it's not capturing the new -- all the additions that have gone into the Company's asset portfolio. So if you're looking at backward year average, you're going to lose the things that are driving taxes up.

Transmission power delivery and bad debt expense is appropriate. Overhaul expense, the O&M escalation, and mine royalties, all of these things are covered in testimony. And again, I don't want the Commission to think that by not giving them a lot of treatment here means that the Company is abandoning its position.

Because the incentive plan was talked about at some length, I'm going to take a minute to note that a little bit. And it's because the Commission, the Chair, asked a question about it. The Chair asked the right question, which is: Do our past decisions say that no incentive plans that are in any way tied to financial performance should go into base, or only those that are significantly based on financial reward?

And, contrary to what we heard, the answer to the question is, in fact -- as I assume that the Chair knows -- that it only is inappropriate to put into base if the primary objective is the financial goal. That was decided in the U.S. West Communications case that was a Cross Exhibit B that was discussed with Mr. Higgins. The cite is 1995 Westlaw 798880, and I will just read one quote because it was a question. The quote is, "The Commission reiterates its policy that an acceptable incentive compensation plan to be recoverable in rates must have as its primary objective customer service goals not financial goals."

So that is the standard: Is the primary

objective customer service? Or is the primary goal financial?

So that's the question for this Commission. And does the Commission have any evidence to base that on? The answer is yes. I'm going to call the Commission's attention to the cross-examination (inaudible).

(Court reporter interruption.)

MR. MOSCON: Sorry. And thank you for interrupting me.

The cross-examination of UAE witness, Mr. Higgins, and specifically on page 238 and a question starting at line 3, and then the answer goes through line 19. And I'll only read a part of it.

Mr. Higgins agreed, and I quote, "I agree that the large majority" -- and he's speaking to the incentive plan -- "does not relate to financial performance." So that's a concession that Mr. Higgins already made, which based on the appropriate standard from the U.S. West case, means that the incentive plan should come in. And, again, I don't mean to overemphasize that compared to the rest of these items, it's just something that there was a question on previously.

So finally, I'm going to turn to cost of service. And let's talk about AMI because there were a lot of questions about AMI and used and useful.

And hitting that topic head on, the meters and the supporting system will be used and useful for customers.

Now, first I wanted to talk about what the appropriate standard is. Again, the Commission is not in a vacuum here. This has been analyzed in this state before. In the Terra Utilities case, the question was: What happens when you have a project that is only partially used? And the answer is that the project does not have to be fully complete and benefiting all customers to recover for the used and useful portions.

So what that means is if you have a plant or a project that is partially used and partially useful, you can get in base the actual cost for those portions that are being used and that are useful to customers.

So that's the question for the Commission is, okay, for AMI, of the amount that the Company is seeking, how much of that is going to be in service during the test period or those expenses will incur, and are they going to be useful for customers?

And the answer to a question that was also, I think, raised, and I think I heard DPU's counsel very correctly pointing this out, is that the transcript shows 80 percent of the system and at least 35,000 meters will be fully operational within the test period. And customers with meters will have access to 100 percent of the benefits of the AMI meters during the test period.

I would also point out, and this was testified by Mr. Mansfield, that the Company is not seeking to put in rates costs for any meters or other equipment that will not be installed and used during the test period. So we are not putting the full AMI costs in this case. The only AMI costs in this case are those costs that are going to be used and useful to customers during the test period. So the fact that the entire AMI system is not fully operating, that is not a reason to deny recovery, and that is the Terra Utilities case, which says to the extent that you have a part of your system in service and it is being useful, then the Commission should allow recovery for that expense.

And this is just what I've already said. We're limiting the costs that have been accrued and that will benefit customers.

I will note for the Commission if you're going to buy, for instance, a software system or a licensing fee that's going to apply for, you know, 100,000 meters -- and I'm making these numbers up -- you incur that expense for the first meter but then it applies equally for other meters.

So the costs of some of the facilities, as

Mr. Mansfield explained, have had to necessarily occur in this order that are now in place, and they will -- those costs will continue to serve additional meters that come online. That's going to that 80 percent of the system. That system has not fully been built out, but we're only seeking to recover the part of the system that is going to be built out and used in the test period.

Moving to rate design, specifically the proposal to eliminate the third summer tier. Company's testimony shows that tiered rates cause artificially high bills and unfairly impact larger households, which is a significant thing in this state. More people in a house tend to use more electricity. Also, electric vehicle owners who charge at home -- another thing that the State of Utah is trying to encourage -- these are the types of customers that are being unfairly impacted by the current design.

There's no economic justification for these tiered rates because overall customer usage in a monthly period does not make it more expensive for the utility to produce the next kilowatt hour of electricity between tiers. And therefore, it's not cost justified and is overcharging the customer that moves from the second to the third tier.

There was a point made that the proposal does not result -- or results in inequitable bill impacts.

That is not correct. This table from Mr. Meredith's rebuttal shows that that is the case, that the low-usage customers actually see less of an increase than high-usage customers, and the high-usage customers will see the highest increase compared to the average customer. So the proposal is not going to have an inequitable impact on the low-use customers.

Let's turn to the customer service charge. The proposed single family charge of $10 is necessary to cover costs of service. Line transformers should be included in customer charge. The cost of the transformer is unaffected by usage, and the Office's argument that transformers should be recovered through a volumetric component does not make sense.

The cost of transformer does not increase proportionally based on customer size.

Line transformers generally serve small customers and are located geographically close to the customers served.

Let's move to 6A, the proposed redesign of 6A. The proposal is declining kilowatt per hour for Schedule 6A customers. The first 50 kilowatts for each kilowatt of demand will be charged a higher rate, and all additional will be charged at a lower rate.

No party opposes the creation of this redesign rate, but several parties argue that the current 6A should be retained as well. That would create a revenue deficiency for the Company that could be as high as $2 million. Keeping the old 6A at the same time that you do the new 6A simply creates a revenue deficiency.

MR. MOORE: Excuse me, I'm going to apologize here, but I'm going to object to the continuation of the closing statement. Rocky Mountain Power is over their 60 minutes allotted time, from the OCS calculations. Thank you.

MR. MOSCON: I'll respond if you want, Mr. Chairman. It's probably true, and the reason is, is because I've been answering the questions kind of that came up now. I guess I could have, and perhaps should have just done the presentation and then answered the questions that, of course, weren't tracked against anyone's time.

I will note that we only have a few slides remaining, but it is certainly the Commission's discretion, and I will do as indicated by the Chair. But that's, I think, the reason for the time discretion.

CHAIRMAN LEVAR: I do understand both the objection and the explanation you just gave.

Is wrapping up in maybe one or two minutes possible, Mr. Moscon?

MR. MOSCON: I am trying to look to tell you exactly how many slides I have left. But I think it's -- well, I think we only have two topics left, so yes. Let's just move quickly.

Schedule 32, the delivery facilities charge would recover from customers the fixed costs. It ensures that these customers pay their fair share of distribution and transmission costs.

There's one clarification note that I wanted to make, and that is that the Schedule 31 and 32 customers are different because the service they receive is different, and generation from an on-site resource is fundamentally different than generation from an off-site resource. These are different concepts that shouldn't be conflated.

Just because of time, I may skip some of this, although I don't want, again, the Commission to feel like we don't have responses to these things.

The facilities charge will not discriminate against Schedule 32 customers. We are ensuring that Schedule 32 customers are not able to avoid costs of the distribution and transmission system that they should pay, and it's a modest increase.

So again, I pointed out treating 32 like 31 doesn't make sense because they are different, and it is an unfair benefit to 32 customers.

I'll quickly refer the Commission to Table 6, showing that there is no discrimination for Schedule 32 customers. That was already in the record.

Unbundling is the last thing that I'll spend time on, then. Unbundling would break prices into functional components so the prices listed would show the categories. It allows costs to be delineated from supply to increase the accuracy of the EBA. It's necessary to support the programs envisioned by H.B. 411. It supports transparency. And to accomplish unbundling, it is necessary to subfunctionalize production of transmission functions, meaning production and transmission would be broken into additional subfunctions in the cost of service study.

The Company rejects the Office's argument because it conflates the demand and energy classification with fixed supply and variable cost components.

And I'll just end with this summary: Contrary to their belief, it "is not a secret plan to conflate that which is considered energy related with variable supply. Besides the subscriber solar delivery charge, unbundling does not influence the Company's overall total rate design calculations. It does not make demand charges higher or energy charges lower. It merely slices these categories up for convenience. It doesn't change the total price."

Thank you. I know I rushed through those final slides because I understand the objection as well, and the Company was not trying to take advantage. But thank you. If the Commission has questions, I'm going to try and remove this and go back to regular screen now.

CHAIRMAN LEVAR: Thank you, Mr. Moscon. Why don't we take a 10-minute break, and then we'll move to questions from the Commission for Mr. Moscon.

MR. MOSCON: Thank you.

(A break was taken from 12:04 p.m. to 12:15 p.m.)

CHAIRMAN LEVAR: Commission Allen, do you have any questions for Mr. Moscon?

COMMISSIONER ALLEN: Thank you. I do not have any questions.

CHAIRMAN LEVAR: Commissioner Clark?

COMMISSIONER CLARK: Yes, thank you. I have a question or two.

First, with regard to the Pryor Mountain project. I believe the evidence is that a total of 78 wind turbine generators were purchased from BHER, which constitutes, I think, a substantial majority of the generators that are part of the Pryor Mountain project.

And is it Rocky Mountain Power's position that all of those 70-plus needed to be purchased in order to acquire the safe harbor protection for the project?

MR. MOSCON: Thank you, Commissioner Clark. I think that there is in Mr. Van Engelenhoven's testimony an answer that I'll try and parrot. But if I get it wrong, it should be there.

"No" is the answer to the question. I think there was 50-plus that needed to be acquired. I think that he talked about the analysis of all of them being right there nearby, low-risk because you didn't have to transport them, the cost, et cetera. But the position was not that you had to acquire every single one of them to get the safe harbor provision.

COMMISSIONER CLARK: I appreciate the reference. I was frantically looking for that during the break, and I couldn't find it. But I'll -- if I know it's there somewhere, I am looking for that piece of information. So, thank you.

Entirely separate subject now.

MR. MOSCON: By the way if it helps, I'll tell you that it's in the November 3rd transcript. Sorry. Go ahead.

COMMISSIONER CLARK: Oh, thank you. Okay.

Regarding AMI, I think from a statement of one of the prior counsel -- I think actually Mr. Jetter -- at least if I understood him correctly, indicated that the 34,500 AMI meters that would be installed sometime during 2021 and reaching that number by the end of the year would be replacing AMR meters.

Is that your understanding as well?

MR. MOSCON: So meaning -- okay. So some are, not all are. So some meters are coming -- well, I think the point is in addition to those, there are the new meters coming on. So I don't know if this is answering your question.

I think, yes, that number reflects the replacement. But in addition to those, there is some new construction, new metering that is going to come online as well. That is my understanding. Again, I hope I'm not stating it incorrectly. But this, I think, was testified to by Mr. Mansfield, but that is my understanding, that that is the number that are replacing the AMRs, I think.

COMMISSIONER CLARK: Okay. And will those new AMI meters that replace existing AMR meters be performing any task in the test year that the AMR meters did not perform?

MR. MOSCON: Yes. And I don't pretend to know the detail as well as Mr. Mansfield. But yes, they do.

There is an ability of customers to be able to ascertain or understand -- I'll just give you an example. I'm not saying this is the highest and best use.

But if a customer called up and said, My power bill skyrocketed, and I'm trying to figure out why. With the new technology, they'd be able to get a level of detail that otherwise is not.

The power company could look and say, Well, it looks like every Wednesday evening your power is spiking up.

And someone could say, Well, that's -- oh, my son comes home and uses the hot tub that day. I mean, I'm just making up a facetious example. But it would allow them to understand the drivers behind their bill in a way that is not -- you're not able to do with the old technology. Where before, you could say, Yeah, so far this month you've used X power, but you can't differentiate it in that way.

Now, that's just an example. I'm not saying that's the whole reason behind the AMI. But I'm saying, yes, there are benefits in addition to those that are already in existence with the AMR meters.

COMMISSIONER CLARK: And so the IT portion of the project will be functional to that extent, that it will allow these additional capabilities even though it won't be completed by the end of the year?

MR. MOSCON: So, again, I don't want -- I want to be careful and not overstate.

My understanding is that, yes, that even though that the -- I'm calling it the system, not the meters -- is going to be 80 percent complete, but the software function is either going to be entirely complete or sufficiently complete that that type of information is going to be ascertainable.

I think that there are other software benefits that involve meshing when communities get built out and these meters can talk to each other and do different things that may not have come online yet or will be coming online as this system grows. And the different benefits for having this mesh network and meters talking directly to each other you may not see until the system is further built out.

But that ability of interface between the Company and its customer, my understanding is yes, that is going to be used and useful.

COMMISSIONER CLARK: That concludes my questions. Thank you, Mr. Moscon.

MR. MOSCON: Thanks.

CHAIRMAN LEVAR: Thank you. I just have maybe one or two follow-ups.

Is there a way that we could estimate based on what's in the record, of these 35 AMIs that are estimated to be in by the end of the test year, should we just assume it's an approximate 1/12 of them going in each month of the test year, or do we have anything else on the record --

MR. MOSCON: No. No.

CHAIRMAN LEVAR: -- more specific than that?

MR. MOSCON: It goes against everything that I was educated to do in law school. I think I have to say I don't know the answer to your question, and I just don't want to give you wrong information. It's something that I can find out if the Commission wants to take a one-minute break, but I just truly don't know if that's in the record or not.

CHAIRMAN LEVAR: Moving more to a legal question.

As we look at test-year issues for both AMI and Pryor Mountain, it is the case, isn't it, don't you agree, that we have to look at amortization over the portion of the test year that that facility is in, not just that if it's in by the end of test year it's considered having been in for the entire test year, right?

MR. MOSCON: No dispute. I'm looking at the result of that. So the Company is not in any way trying to capture an entire year of costs for a portion of a year of use. And I'll talk to the -- for instance, that's the rationale for this two-step approach for Pryor Mountain, for instance, which is that we're not going to put that into rates until that is online and useful and providing benefits to customers. The cost has all occurred during the test year.

And I don't know if this is a helpful analogy to answer the question that you have, and I'm probably going to highlight my own limitations here. But if you'd had -- and just because it divides out, I'll use a $60 million project because that's $5 million per month for a year.

If you had a $60 million expense and you had it all year long, and you had a $5 million per month in service charge compared to waiting until something becomes available on July 1st and you have $10 million per month charge, the total net for the year is the same, meaning the cost is the same but customers are only paying for the benefits as and when they are used. And that, I think, is just a soft analogy. And it's so simple that, of course, you can come up with all kinds of problems with it, but I'm trying to demonstrate that the Company is not seeking to avoid that average or to recover costs when there is not a use of the product.

CHAIRMAN LEVAR: Thank you. I think for the most part, any other questions I had left were covered in your presentation.

Although, you did -- you answered the question I posed at the beginning about whether that number from Dr. Zenger's testimony remains confidential. And you alluded to a file number that is still confidential. We have not been able to identify that that's in the record, that final number that you stated still remains confidential.

If you're aware of it being in the record, could you direct us to anything? But our quick-and-dirty search kind of indicates that it may not be in the record.

MR. MOSCON: Just because of when all this stuff -- you know, how this -- looking back to when the decision was made and was based on that estimated number, I think I'm going to guess that the Chair is correct. I don't know, as I'm sitting here, that that number is in the record. And again, I hope I'm not misspeaking. But I'm saying that I think there is an actual known number, but that may not have been there when the testimony was filed. So the Chair may be correct. And if that's something that it wants supplemented, I just don't want to, again, tell you, Oh, sure, Mr. Link talked about it.

Because I'm not sure that it is there. I think the Chair is correct.

CHAIRMAN LEVAR: Okay. No, I just wanted to give you the chance if you were aware of it being in the record somewhere to tell us. But I appreciate that answer. And that's all the questions I have.

And so with that, unless anyone else has anything else for us, I think we're completed for the day. I'll give a moment, if anyone has something else, to unmute yourself and state it.

MR. MOSCON: Do you mind if I correct one thing? I was told I misstated something, and I just don't want the record to be unclear.

I, in the cost of service, referred to Mr. Meredith's Table 2, talking about the impacts on customers. And I believe my characterization may have indicated that Table 2 is analyzing customers by high and low use. And I am told that that is not correct, that it is based on the decile by percentage of category of customers. And if I knew enough about cost of service to distinguish between the two, I would elucidate. But I don't, and I'm not. I'm just telling you the Company is not trying to mislead the Commission through counsel's ignorance on the subject.

CHAIRMAN LEVAR: Okay. Thank you, Mr. Moscon.

Anything further from anyone else?

I'm not seeing or hearing anything, so we are adjourned. Thank you.

(The matter concluded at 12:27 p.m.)

CERTIFICATE

State of Utah)
ss.
County of Salt Lake)

I, Michelle Mallonee, a Registered Professional Reporter in and for the State of Utah, do hereby certify:

That the proceedings of said matter was reported by me in stenotype and thereafter transcribed into typewritten form;

That the same constitutes a true and correct transcription of said proceedings so taken and transcribed;

I further certify that I am not of kin or otherwise associated with any of the parties of said cause of action, and that I am not interested in the event thereof.

WITNESS MY HAND at Salt Lake City, Utah, this 16th day of December, 2020.

Michelle Mallonee

Michelle Mallonee, RPR, CCR
Utah CCR #267114-7801
Expires May 31, 2022

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