PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, July 11, 2023

TIME: 10:00 a.m. - 12:41 p.m.

DOCKET NO: E-34, Sub 54 and E-34, Sub 55

BEFORE: Commissioner Karen M. Kemerait, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Appalachian State University d/b/a

New River Light and Power Company

E-34, Sub 54

Application for General Rate Case

and

E-34, Sub 55

Petition for an Accounting Order to Defer Certain

Capital Costs and New Tax Expenses

VOLUME 3

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TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER KEMERAIT: Good morning. Let's go back on the record. Before we get started, we have one preliminary matter that I would like to address. Commissioner Duffley is -- she has a conflict for a short time this morning.

Do any of the parties have any objection to her reading the transcript during the portion of the hearing in which she has to be away?

MR. DROOZ: No objection.

MR. MAGARIRA: No objection.

MR. FELLING: Public Staff has no objection.

MS. LaPLACA: No objection.

COMMISSIONER KEMERAIT: Okay. Let the record reflect that none of the parties have any objection.

With that, we will proceed with witness Barnes, if you can return to the witness stand.

Whereupon,

JUSTIN BARNES,

having previously been duly sworn, was examined and testified as follows:

COMMISSIONER KEMERAIT: Good morning,

Mr. Barnes, and you're still under oath. I believe that there is some additional questions from the Commission.

Chair Mitchell?

EXAMINATION BY CHAIR MITCHELL:

Q. Good morning, Mr. Barnes. Just a few for you. I want to walk back through your testimony on Schedule NBR. And Commissioner Clodfelter covered some of this with you yesterday, but I just want to make sure I understand your testimony. And more specifically, the analysis that you performed.

Just at the outset, can you walk me through your understanding of the schedule -- Schedule NBR? How does it work? If I were a customer wanting to participate, how does it work?

A. I mean, it's basically like, kind of, traditional net metering, insofar as you're able to offset electric usage onsite, kind of, directly.

You know, as your system, you know, produces electricity, it goes to your house first and then onto the grid if there is excess. That excess is, essentially, kind of, rolled forward, and then offsets, you know, future times when you are pulling electricity from the grid at a one-to-one, you know, retail kilowatt-hour basis.

You know, as the Company initially proposed, that accumulation of credits was reset on January 1st, and then later, kind of, voiced some openness to, you know, other options for that reset.

Q. Okay. And the SSC, how does that work?

A. It's a monthly -- you would consider it, kind of, to be a monthly fixed charge, based on the nameplate capacity of the system. So, you know, $6 times whatever the system size is, is your monthly additional charge that you pay in addition to the fixed customer charge.

Q. Okay. And what is the limit on system size?

A. If I remember correctly, it's 20 kilowatts for residential and 1,000 kilowatts -- I don't have the tariff in front of me -- and 1,000 kilowatts for nonresidential.

Q. Okay. That sounds about right. Okay.

So your testimony covers some of the issues that you have with respect to the methodologies that the Company used with respect to this tariff.

So I'm interested in what you call the first error. Can you walk me through the first error?

A. Sure. So if you were to look at witness

Halley's Exhibit REH-19A, what you're gonna see is a --

Q. And that's to his direct testimony?

A. That's to his direct testimony. There are other versions of that that had been, like, filed supplementally as, like, revenue requirements change.

But essentially, what witness Halley did, is he took -- first, made a calculation of what the effective, kind of, capacity of customer-sided solar would be at offsetting demand costs. And that's done based on, you know, the level of alignment between solar production from some of the solar production metering data that they have with the Company's, you know, peaks for DEC transmission, and for BREMCO transmission, for Carolina Power Partners production generation.

So there is -- in REH-19A, you are gonna see, like, these percentages that are applied that effectively, kind of, derate the value according to how well it aligns with the Company's peaks.

Q. So derates the value of the solar system?

A. Yeah. It's like saying, well, we can only expect a 1-kilowatt system to produce 200 watts, based on its production profile at the time of, you know, the monthly peaks for -- to determine our costs for

Carolina Power Partners. So it's, like, an effective -- apologies -- like, an effective load-carrying capability, or something similar to that.

Q. Okay.

A. Now, I don't have an issue, necessarily. Sorry, I think I keep interrupting.

I don't have an issue -- you know, if that's an appropriate thing to do when you are trying to define what the value is for solar against time-varying -- time-varying rates, rates that are different, depending on what time demand is incurring. That's, kind of, a feature of all valuation of solar studies.

The issue I have with witness Halley's testimony, is that, what he multiplies those percentage numbers by is the flat volumetric retail rate for the residential class in his direct testimony, and then he did similar calculations for the other classes in his rebuttal testimony.

The problem with that is that, now you've already gone and derated solar based on its ability to, kind of, match the Company's peak, the determined cost. When you base the other part of that calculation on the flat volumetric retail rate, you're essentially further derating the value, because you have taken something that is a cost that's caused by demand during peak periods and then averaged it across all customer usage, because that's what the flat volumetric retail rate is.

So you've taken, you know, what amounts to cost caused by peak demand and reduced that to an averaged cost, or the cost of average demand. But that doesn't -- you know, that doesn't change the fact that those costs are still caused by demand during peak periods.

So my calculation, rather than use the volumetric retail rate, I calculated the unit costs on a dollar-per-kilowatt basis for the respective demand-related costs. I applied a, you know, effective solar capacity contribution to those and came out with a -- you know, a dollar amount.

So if the unit cost is, you know, $50 per kilowatt, and solar's capacity contribution is, you know, 20 percent, then the value is $10.

Q. Okay. So that's helpful testimony, and I'm gonna ask you to go through it again, but more slowly and more simply. And I want you to do two things.

First, explain what the Company did. You've already done that in your testimony just now, so I'm asking you to go back and do it again.

A. Okay.

Q. Explain what the Company did, and then explain what you did.

A. Okay. The Company's calculation in terms of --

Q. And to be clear, we're talking about the develop- -- the methodology for the development of the SSC; is that correct?

A. That's right, yes.

Q. Okay.

A. So the way the Company, you know, calculates the value, in terms of -- value of solar in terms of dollars and cents, dollars per kilowatt hour, is average retail rate times the effective solar capacity contribution.

So it's, you know, 3.5 cents times 20 percent produces the value rate. And they do this for multiple different demand-related costs. BREMCO distribution, Carolina Power Partners production demand, and DEC transmission. When they calculate that value -- so what you end up with is, as reflected in the initial REH-19, is a value of about 7.9 cents per kilowatt hour after all is said and done.

That includes other, like, energy-related costs that are just passed through on a one-to-one basis, as well as, you know, those, kind of, derated dollars and cents per kilowatt hours per demand-related costs. You sum that up to, you know, 7.9 cents.

You look at -- well, basically, the calculations aren't exactly like this, but basically, you look at, well, what's the retail rate? What is the rate at which the customer saves? According to the initial testimony, it's about 14.8 cents per kilowatt hour. 14.8 cents, minus 7.9 cents -- you know, the cost is 14.8 cents per kilowatt hour, that value is 7.9 cents per kilowatt hour, you have, you know, a deficit.

You take that deficit and multiply it by the Company's, you know, expected solar production from, you know, the -- a unit of systems, and you come up with, you know, a dollar amount for what the -- for what the deficit would be.

Then you divide that by, you know, a reference amount of capacity in order to create the capacity charge. So you say, you know, there's a $1,000 deficit across, you know, the residential class; there are 50 kilowatts of residential systems;

therefore, the standby charge is 1,000 divided by 50. Those aren't the exact numbers, but.

Q. So you've said capacity charge and standby charge, but what you're specifically referring to is the SSC?

A. The SSC, yes.

Q. Just want to make sure the record is clear. Okay. All right.

So that's what the Company has done. And then what is your -- what is your proposal? How would you do it?

A. The only difference in that calculation that I made was, rather than use the flat volumetric retail rate, I used a -- the unit costs, which are derived as -- basically, take all of the costs associated with this particular cost setter, like Carolina Power Partners, for the residential class, divide that by the demand for which that -- the demand factor that determined that allocation to the residential class, and you get a unit cost, dollars per kilowatt. That's the cost of residential demand during peak times.

So rather than use the residential retail rate, I used that number to then calculate -- you know, did the calculation of effective solar capacity, multiply that by the unit costs, and you get a dollar amount. And that's, you know, the amount that a given tranche of solar would save New River Light and Power over the course of a year; because we're talking about the test year annual period.

To translate that to a solar value rate, I divided that by, you know, expected solar production per year. So divide $10 by 1,200 kilowatt hours for each kilowatt, and that produces the -- that produces my estimate of the value of customer-sided solar, in terms of dollars per kilowatt hour.

I should also -- I should also mention that, in addition to -- because of some of the, kind of, like, missing data issues associated with the Company's solar -- like, actual solar production metering data, I did -- I constructed multiple scenarios just using, kind of, like, hypothetical solar production profiles, just to see whether or not, like, those effective solar capacity contributions would differ a lot.

Q. So I'm gonna stop you there, because I need you to help me understand where those -- where the solar production comes into the calculation.

So the Company starts by looking at the solar production or solar output during its peak periods; is

that correct?
A. Right.
Q. And so is that where they're using the metered data?
A. That's right. They use that to construct those percentages that I mentioned.
Q. Okay. And so is that where the missing data becomes problematic, when they're developing those percentages?
A. Yes. That's -- because, as I mentioned, there are a lot of daylight hours missing from those hourly numbers.
Q. So do I understand your testimony to be that the -- you used effective capacity of solar production, but the contribution that solar is making during peak periods is understated because of the missing data. Is that your testimony?
A. I guess not exactly. The -- I noted that because it's a -- I think it's a -- it would be preferable to be able to rely on actual, you know, metered production data in order to make these calculations, because there are lots of variations in systems that, you know, might cause systems in New River Light and Power's territory to be a little bit

different than a hypothetical south-oriented or southwest-oriented system.

So my preference would have been to use actual data, except, you know, when you're faced with that amount of missing information, you know, it caused me to, kind of, go in another direction. So rather than try and fill in all of those blanks, I decided to, kind of, perform a sensitivity analysis, and look at the same question using a hypothetical south-facing solar, hypothetical southwest-facing solar, hypothetical southeast-facing solar.

Q. Is that where you relied on PVWatts?

A. That's why I relied on PVWatts.

Q. So the issue you have -- so let me back up. The difference between your calculation and the Company's calculation, as I understand your testimony, rests on your use of unit costs versus the Company's use of the -- that -- the volumetric rate.

Do I understand your testimony correctly?

A. That's right.

Q. Okay.

A. Demand unit costs versus flat volumetric retail rate.

Q. Explain one more time -- this may be your third time, maybe your fourth -- why your preference is for the demand unit cost.

A. Because the volumetric residential retail rate is reflective of those demand-related costs spread across all hours of the year, spread across all customer demand. And therefore, it diminishes the -- it, essentially, kind of, eliminates the time-varying character of those costs.

And yet we've already performed an adjustment to reflect how solar contributes to the time-varying character of costs. So we've effectively derated the value of solar twice; once by reasonably -- by calculating an effective capacity factor, and another time by using an averaged -- the average cost of demand, rather than the cost of peak demand.

Q. Okay. So the -- you use the word "derate," and you said the Company derates -- or you testified that the Company derates the solar twice.

But isn't it actually the case, when the Company is looking at the solar's contribution to peak periods, is they're trying to determine exactly how much that solar facility is contributing at that moment in time? It's not necessarily a derate, it's what is solar doing at this moment in time?

A. Yeah, right, it wasn't -- it wasn't -- I entirely agree with that exercise of calculating effective solar capacity.

I used the term "derate" just because I couldn't come up with another one.

Q. And that's fair. I just wanted to make sure I understand. You're not saying that the Company unfairly penalized the solar once and then is penalizing them again. It's just that they -- the Company arrived as a contribution to capacity -- I mean a contribution to peak, which takes into account how much solar is contributing at a specific moment in time?

A. Right. Yeah. And I did the same thing in my --

Q. Right, okay. I just wanted to make sure that I'm clear and that the record was clear. Okay.

Can you -- I think you have gotten me there, so I apologize for making you go through all of this again with me.

The -- your testimony suggests that there not be a credit reset at the end of the year, or January 1st, as proposed initially by the Company; is that correct?

A. That's right.

Q. Okay. And then my understanding, in reading the Company's rebuttal testimony, is that the Company is open to that -- to eliminating the reset.

Is my understanding and your understanding the same?

A. Yeah.

Q. Okay. And then, in the stipulation, suggests that the Company and the Public Staff have had some discussions about this, and I read the stipulation to be that the Company and the Public Staff have agreed to allow this tariff to remain in effect as proposed for five-years, and then to revisit the issue; is that your understanding?

A. Yeah. That's my understanding as well, since I didn't see anything saying that that annual reset should change in the stipulation.

Q. Okay. Okay. When you were working through your understanding of the Company's methodology and developing your own methodology, did you discuss -- did you have any discussions with the Public Staff?

A. I didn't have any kind of, like, informal discussions with the Public Staff.

Q. Okay. Did you -- in your review of documents and records in this case, did you review the Company's agreement with Carolina Power Partners?

A. I don't think I reviewed the specific agreement, but I did review, basically, a spreadsheet that's, kind of, detailing what their costs to Carolina Power Partners are and how those costs are -- how those costs are incurred.

Q. Okay. When does New River's peak occur?

A. Principally, in the mornings during the winter, and during the afternoons during non-winter months.

Q. So when is the -- what was the highest peak for New River during the test year?

A. I think the system peak would have been in January, but I don't remember that specifically. It is in my work papers.

Q. Okay. Like 6:00 in the morning?

A. It was later than that. It was either 8:00 or 9:00, I think.

Q. Okay. All right, I have nothing further. Thank you, Mr. Barnes.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Let me just follow up on a couple of Chair Mitchell's questions.

In regard to the annual reset that's in the Stipulation, that it will be reviewed in five years. Presumably during that period, there would be more subscription to the NBR schedule, and also some more data.

So can you explain why a review in five years you would not be recommending or you think would not be appropriate? What is the problem with waiting for the five years for a review at that time?

A. Well, my concern would be that, you know, all of those customers that participated are gonna be overcharged for five years. You know, I certainly don't have a problem with -- with a review on any cadence.

I think what I would -- what I would prefer is that, based on my analysis, kind of, full net metering without the standby charge, be allowed to go into effect. And perhaps when the Company can, I don't know, fix the production metering issues and develop, kind of, a complete data set, that maybe that could be reviewed in two year's time, or something like that.

I don't know why it's necessary to wait five years. I guess I don't have an ideological position on what timeframe is necessary. It feels like it's at least a year in order to assemble the additional data.

Q. To make sure I understand, though, isn't the overbilling issue that you're talking about that, isn't that a separate issue than the annual reset? That is a separate issue than -- that you want -- that needs to be solved, in your mind, or your position, in a different way than annual reset; is that correct?

A. Well, so if we have that annual reset on January 1st, the way the Company did the calculations, they didn't take into account that customers may forfeit a certain amount of their excess production over the course of the year.

So there would be -- you know, the two are, kind of, interconnected in that way, the supplemental standby charge and the annual reset. So all other things being equal, that would have to be, kind of, fixed in, say, setting a supplemental standby charge if that element was retained.

You know, given that customers would presumably understand that sizing their system up to 100 percent would result in the forfeiture of credits, you know, having a review in five years' time with customers, kind of, fully informed and able to size their systems so that they don't incur that forfeiture, that could be reasonable.

I dislike the fact that it really prevents you from sizing a system in a way that lets you fully offset your on-site load.

So that's, kind of -- that would be, kind of -- that's my principal, kind of, objection to that annual reset, beyond, kind of, the calculations, is that, you know, it doesn't let you offset all -- it doesn't let you offset all of your on-site load over the course of a year without incurring the forfeiture of credits.

Q. And then one last question for me. This relates to the SSC. And I want to give you an opportunity to explain again, or to better explain, why you think that it should be based on the system design capacity rather than the nameplate capacity of the inverter.

So I know you touched upon it a little bit yesterday, but can you, again, explain why you think that the Company's position about that is incorrect?

A. Okay. So I can use a specific example of a system I installed on my home in Raleigh years ago. The nameplate capacity -- like, the nameplate capacity of the solar panels on my roof is 2.9 kilowatts. The nameplate capacity of the inverter is 3.5 kilowatts.

The reason why the nameplated capacity of the inverter is higher than the nameplate capacity of the system is just because they don't make 2.9 kilowatt inverters. They -- you can't necessarily directly match the size of the system with the size of the inverter.

The problem with using the inverter size is that it's often the case that the inverter is gonna be sized at least somewhat larger than the design capacity of the system. And the design capacity of the system, not the inverter size, is really what determines how much energy it produce -- it produces.

So when you've got a calculation of an SSC that's really, kind of, at its core still based on how much electricity is the customer avoiding purchasing from New River Light and Power and what is the cost of that, you have to use the system production capacity, not the inverter nameplate capacity.

Q. And is it -- is there any difficulty for the Company in providing -- I think, providing the nameplate capacity of the inverter is, kind of, a simple exercise.

Is it any more difficult for the Company to have information about the system design capacity, as opposed to the inverter capacity? Is there -- administratively, is this going to be problematic for the Company?

A. I don't see any reason why it would be. I mean, you can collect -- you could collect that both pieces of information as part of an interconnection agreement. I mean, I think they actually do that already. It's a line on the form.

Q. Okay. Thank you.

COMMISSIONER KEMERAIT:

Commissioner Hughes, did you have a question?

EXAMINATION BY COMMISSIONER HUGHES:

Q. One, just quick follow-up on the inverter question. I mean, I know we're only talking about 10 systems, but in the data, or whatever they had the data for, did they actually look and see if the outputs were higher than the nameplate capacity? I mean, I understand the 2.9, but, I mean, you probably actually followed your system, I imagine, quite closely.

Has it ever produced more than 2.9? Because even that 2.9, I understand, is an estimate, so.

A. Yeah. I mean, it wouldn't be capable of producing more than 2.9, because that's, like, the maximum rating of the panels, themselves. Like, each panel is X amount, and you sum them all together, and that's the design capacity.

I don't think they -- I don't know that New River Light and Power -- they don't know the capacity of all the current systems. There's -- I think they know 9, and 6 are missing.

Q. I just didn't know the technical -- I didn't know if the 2.9 was an underestimate, but you answered it. The 2.9 is the absolute physics cap for your system?

A. Right, that's correct.

Q. Okay. I thank you for going over with Chair Mitchell the explanation of the SSC. I think I understand it myself now.

The way I would look at it -- and I just want to verify that it's correct -- is there was a lot of effort to try to figure out when the solar systems are producing the energy, but there was not any effort, really, to figure out the cost that matched with that time when they were producing it. Rather, instead, they fell -- you know, they fell back on an average price, which is very different than cost.

So is that, kind of, the -- is that, kind of, the unequal treatment, is, you know, they did go ahead and figure out when it's going into the system, and there is good data on the actual costs then, because you have the contracts, but they didn't use those costs, they just went back to using --

A. Yeah. They used what I would call, kind of, the proximate costs in New River Light and Power. And the proximate costs, if you're looking at, you know, what the solar cost-benefit equation, is how much do customers save? And that's determined by those -- all of those flat volumetric retail rates.

So I don't have an issue with, kind of, calculating costs based on that -- using, kind of, that equation. Because, literally, if a customer saves $100, it's $100 that New River Power doesn't get now. Now, the customer is provided something else in exchange for that $100, but I don't have a problem with saying the cost is basically system production times the retail rate, because that's what a customer saves.

Q. Okay. Did -- I'm not sure of the timing of when you did most of your analysis and whether it was pre or before -- I mean pre or after the -- some of the new subsidies and credits that we're gonna see rolling out for batteries and for systems -- for solar systems.

But first off, did you look at those and just run any kind of analysis -- or have you done it for other types of analysis that you've done -- the impacts on those -- those customer credits for solar systems, but also for batteries?

And I didn't see a lot of discussion in batteries in this case and storage, what would happen. You know, but if we're talking five years, this is system -- these rates are in place for five years.

If in three years the cost of battery storage is much lower and a customer could conceivably greatly increase that capacity factor by having on-site storage, then it would seem like that there is a large underestimate of the value of that electricity going back to the -- back -- you know, back into the system. Does that make sense?

A. Yeah. So I guess there's a few things -- there's a few things I want to say, if you'll indulge me a bit.

So one, I didn't do, like, a payback-period analysis or anything -- or anything like that. Like, I didn't look at what the financial impact of the supplemental standby charge would be on, like, customer savings or, you know, how long it would take their system to pay them back for what it costs them. So that wasn't -- that just wasn't part of my -- wasn't part of my, kind of, consideration.

As far as batteries are concerned, you know, with a flat retail rate, you know, that being what it is, there's not really -- there's not really a use case for batteries for the customer. I mean, they don't get anything out of having a battery, other than, you know, back-up capability.

So they wouldn't have much of an incentive, under the current rate structure, to, kind of, operate a battery in a way that, you know, is, kind of, increasing the value of their system. That could be accomplished if there were, like, time-of-use rates that were, kind of, telling them when -- you know, when energy was more expensive or less expensive.

But kind of under the flat retail rate structure, they don't really have -- they don't really have a reason to, you know, really use the battery at all, other than to provide back-up power.

But, in theory, yeah, you could do a lot of things with batteries; one of those is, kind of, you know, firm up the contribution to capacity, you know, by, you know, saving that electricity -- that excess electricity that would have gone on the grid at 2:00 in the afternoon, which is off-peak, and then, you know, discharging it at 6 p.m., which is more likely to be an on-peak period.

Q. Makes sense. If the reset does occur, then there would be a small value add for potentially reducing that reset amount, right? That batteries would conceivably allow you to possibly reduce the reset amount or --

A. I mean, the maximum storage capacity of a typical residential battery might be 13 -- 13.5 kilowatt hours. So might be -- you could reduce it by -- I guess, by that amount. But that would be -- it would be, kind of, small potatoes in the context of, you know, what you might expect it to be, which could be hundreds of kilowatt hours that get forfeited.

Q. Okay. And then just to -- you can indulge me further. So, in your opinion, this -- anything that we're looking at would not be an incentive for further reduction of cost the utilities are gonna incur by using batteries. There is no incentive on the customer level, there's no incentive in the rider that we're looking at to encourage storage, even though we know that it would be possible to reduce the utility's costs and therefore, the customer basis cost.

A. Right, yeah. I mean, there is no ingrained incentive in the rates, and there is no ingrained incentive in Schedule NBR, as opposed to use storage.

Q. Does that concern you?

A. In an ideal world, we would have time-of-use rates. I mean, that's something I would, kind of, consistently fall back on. Time-of-use rates are better than flat rates that reflect in cost causation, and that would, kind of, create -- you know, that would create some incentive. Whether that's enough to, kind of spur battery adoption is a different -- you know, is a different question.

But, you know, there other opportunities that, you know, could be deployed. I think you've seen some of those -- you know, some of Duke's recent proposals for using -- I can't remember what the -- the residential load management programs.

I mean, those are the kinds of programs that, in my view, kind of pretty effectively utilize batteries and not underuse them to avoid costs caused by peak demands.

Q. Okay. I think that's it. Thanks for that indulgement.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. And my last question is, is it your understanding that New River is planning to develop time-of-use rates within the next couple of years? Is that your understanding?

A. I don't -- yeah, I recall seeing, I think it was maybe a two- to three-year timeline.

Q. Okay. Thank you.

COMMISSIONER KEMERAIT: Chair Mitchell?

EXAMINATION BY CHAIR MITCHELL:

Q. Yeah. We have one last question.

Is it your position that the SSC should be based on the lower of the inverter or the nameplate capacity of the PV system?

A. It should be based on the nameplate capacity of the -- of the PV system. The design capacity is, I think, how I used that terminology.

Q. Okay. Okay. Making sure that gets the response that we need. Okay. Thank you.

COMMISSIONER KEMERAIT: Okay. I think that's the end of the Commission questions. So we'll now move to questions specifically on the Commission's questions, beginning with the intervenors.

Ms. LaPlaca, if you have any?

MS. LaPLACA: No.

COMMISSIONER KEMERAIT: Okay. Public Staff?

EXAMINATION BY MR. FELLING:

Q. Good morning, Mr. Barnes. My name is Tom Felling with the Public Staff. I wanted to just ask you what I think will be one question, based on the line of questionings you were having with Commissioner Clodfelter yesterday on the standby supplemental charge. And I just wanted to make sure we have this clear for the record.

I think you indicated that the $5.92 standby supplemental charge was inclusive of NRLP's distribution costs.

But are you also aware that that charge is inclusive of the DEC and BREMCO transmission and distribution costs as well?

A. I mean, I guess it's -- the way I've seen the calculation, it's inclusive of a portion of those costs, you know, because of the way the calculation works is you're not fully offsetting those costs.

Q. Okay. I think that answers my question.

Just to be clear, you are aware that all three of those components make up -- at some point make up a portion of the SSC?

A. Yes, I'm aware of that.

MR. FELLING: That's all from the Public Staff.

EXAMINATION BY MR. DROOZ:

Q. Yes. So starting with the last question that you were asked by Commissioners about system design capacity versus inverter, and you mentioned six were missing.

Does did -- that mean six customers did not provide New River Light and Power with their system design capacity, so the utility didn't have that to work with?

A. I mean, I don't know specifically why it's missing; whether it, you know, got shelved somewhere or whether they failed to provide it on their interconnection application. I guess I can't speak to that.

Q. You just know it's missing?

A. I just know it's not there.

Q. Thank you. When Commissioner Mitchell was asking you at the beginning to kind of to describe how NBR worked, and you talked about the off -- the solar generation offsets, the usage that's pulled from the grid, effectively, that means that solar generating customers are getting full retail value for their solar power; is that correct?

A. Yeah. I mean, leaving aside the SSC, that is correct, they're getting, you know, one-to-one full retail value.

Q. And that's better than the avoided cost rate that would be available under buy all/sell all?

A. I don't know the specific cost rate, but -- you know, avoided cost rate, but I suspect that's true.

Q. Yeah. Retail is normally gonna be higher than the avoided the cost rate, isn't it?

A. Sure.

Q. That's the benefit of this NBR relative to the old by buy all/sell all?

A. Yeah. I would say NBR is an improvement in that regard.

Q. Okay. You were also asked about the missing solar production data, and whether that was just left out by Mr. Halley in his calculations.

Do you understand that he created an estimation and used that in his calculation? An estimation for the data that had been missing.

A. Yeah, I understand that. In my testimony, I describe why I don't think his estimation methodology is very accurate. Because -- and to explain specifically, there were multiple durations of missing data that might range from a couple of hours to 10, 12, 14 hours. And the way Mr. Halley filled in that missing data was to take the reading after the missing data and the reading before the missing data, you know, subtract one from the other, and then spread that amount equally across all of those intervening hours.

The reason that's not accurate is because solar produces production according to, kind of, an upside down U-shaped curve. So it's not as though it prices electricity at a flat rate throughout the course of the day. It does it over the course of this U-shaped curve.

So interpolating, you know, multiple hours based on that flat amount spread evenly between all hours just isn't accurate.

Q. Is it -- well, I mean, given the lack of data, there had to be some necessary inaccuracy by estimation, given the fact that it is an estimation.

Would you agree with that?

A. Well, sure. I mean, if you're faced with missing data, you do something about it. My preference would have been to, well, we can't rely on this data, and let's use PVWatts, as I did.

Q. I understand. So you were also asked some questions by the Commission about the annual reset.

And do you understand, from Mr. Halley's rebuttal testimony, that New River was willing to step aside on that issue, that New River's understanding was the Public Staff preferred a reset, that Appalachian Voices opposed a reset, and New River decided it wasn't gonna take a position on that issue, and simply let that be resolved by the Commission between the other parties?

A. Yes, that's what I recall.

Q. Okay. Thank you. That's all my questions.

EXAMINATION BY MR. JIMINEZ:

Q. Mr. Barnes, I have a few here.

Going back to yesterday, Commissioner Clodfelter was asking you about the missing -- what he called the missing data issue; do you recall that?

A. I do.

Q. He cited Miller rebuttal testimony, page 6, line 12, which references Miller Exhibit 1, saying, NRLP adjusted the amount of renewable energy utilized in its development of Schedules NBR and PPR to recognize the portions of hourly data missing from its analysis.

Do you recall that?

A. I do.

Q. Have you had a chance to review Miller Rebuttal Exhibit 1?

A. Yes, I have.

Q. Did it resolve your concerns?

A. No. So that filling in of the missing data, at least in my understanding, was that rather than -- so rather than use the sum of all hourly readings from their production metering to, kind of, develop, like this is -- this is the amount of total solar production associated with these systems, they were able to, kind of, construct another estimate that, I guess, is, you know, presumably not an estimate. It's accurate based on using monthly readings. And that -- you know, that influences the amount of the calculated SSC, because one of the components of that calculation is, well, how much did -- you know, how much does a solar customer generate?

You know, So they were able to, kind of, get at that total amount through another way, just by using monthly readings, rather than just summing all of the hourly readings which have missing amounts.

What doesn't resolve my concerns about that is that there is no way to recreate those hourly amounts that are missing during times of -- during times when -- during times, on the monthly peak, when New River Light and Power would have incurred costs to serve that monthly peak. So you can't -- you can't use monthly readings for that purpose. You know, once it's gone, it's gone.

The second issue is that -- that total production -- that total energy production still doesn't tell us what the actual nameplate capacity of those systems is. And that's another component of the calculation of the SSC that, you know, can't be -- I mean, you could -- I guess I suppose you could recreate it by contacting those customers and getting the information. But New River Light and Power hasn't done that yet. So that doesn't -- you know, the missing data concerns that I raised are not resolved in those respects.

Q. Thank you. So sticking with some questions Commissioner Clodfelter asked of you yesterday, he noted that the size of the SSC is based on the nameplate capacity of the customer's system, the inverter, and he wanted to know the average size of the system; do you recall that?

A. I do.

Q. And you said you had seen the list of customers with solar PV generators and NRLP's responses to data requests that's come up during the proceeding, right?

A. That's right.

Q. And have you reviewed NRLP's relevant responses?

A. Yes, I have.

Q. Could you please tell the Commission the sizes of customer-sided solar, according to what was provided, in general terms?

A. Yeah. There were -- in one of the discovery responses there were nine systems that had a nameplate capacity listed. The average -- I mean, they range from, I think it was, like, 3 to 12 and a half kilowatts. The average was about 7 kilowatts. So that's -- I think it's 9 out of 15.

Q. And have you calculated the average SSC at $5.92 per kilowatt?

A. Well, yeah. I mean, if you say, you know, 7 times, effectively, 6, it would be about $42.

Q. Okay. I think this was also yesterday. Commissioner Kemerait was asking you about the harm that could come from customer confusion about Schedule PPR -- NBR and Schedule PPR, and whether anyone would actually prefer Schedule PPR; do you recall that?

A. I do.

Q. Could you please explain how Schedule PPR and buy all/sell all policies generally effect customer-sided solar generators?

A. Sure. Well, I mean, there is certainly a financial impact. Like, to the extent relative you're comparing it to, say, net metering. If you're on a buy all/sell all, and the buy all/sell all rate is lower than the retail rate, then all of that electricity that you might otherwise use to directly offset your load goes onto the grid and compensated at a lower rate than what you would get if you were allowed to directly offset on-site load.

Beyond that, just say in the hypothetical where the buy all/sell all rate is equivalent to the retail rate, there are potentially other adverse consequences for, say, a residential customer.

One is the creation of taxable income, since it's, you know, amounts that might be distributed via a check that are considered to be taxable income.

I'm aware of certain instances where homeowners insurance companies have refused to cover a solar system as part of the -- you know, the customer's homeowner's insurance policy, because they believe the buy all/sell all arrangement was indicative of the system being a -- effectively, a commercial power plant, rather than a -- you know, an accessory to the home, and have, like, requested that they get commercial liability insurance, rather than having their homeowners insurance cover that system.

There's also potentially, in North Carolina, an adverse property tax consequence, because of the way that the State Department of Revenue has kind of distinguished between customer-sided facilities that, you know, serve primarily the customer's own needs and commercial renewable energy facilities. Those customer-sided facilities are, you know, considered accessories to the home and are exempt from property taxes, to the extent they add value to the home.

Those commercial systems are not exempt from property taxes and are subject to, basically, an annual personal property tax as business property.

I don't know whether the DOR would necessarily say that, under a buy all/sell all, this is a commercial facility, but that is one potential implication. It's not a hypothetical; it has come up in other states.

Q. Thank you. Okay, just a couple more.

Moving to this morning, Chair Mitchell, and later Commissioner Hughes, touched on the -- we spent some time on the solar -- SSC calculation and the average volumetric cost, versus the demand unit cost.

Is it -- just to try and put a bow on it, is it true that the demand unit costs better represents the actual costs avoided by NRLP?

A. Yeah. It -- it more accurately represents the cost of demand during peak periods than the average volumetric retail rate.

Q. Thank you. So, okay. Last couple -- Commissioner Kemerait asked you about the review in five years.

Are you concerned with -- and when we have better data at the end of that, are you concerned that, if the policy goes -- Schedule NBR goes into effect with the SSE as proposed, that we won't see very many sign-ups?

A. It's certainly a possibility. You know, I'm not gonna come out here and predict that there won't be any, but if, you know, there is diminished value for their customer, there is gonna be diminished interest from the prospective customers.

Q. Thank you.

MR. JIMINEZ: That's all for me.

COMMISSIONER KEMERAIT: So we've come to the end of questions on Commission questions, so I'll now hear motions from the parties.

MR. DROOZ: New River would ask that its Cross Examination Exhibits 1, 2, and 3 for Mr. Barnes be admitted into evidence.

COMMISSIONER KEMERAIT: Okay. Seeing no objection, your motion is allowed.

MR. DROOZ: Thank you.

(New River Cross Examination Barnes Direct Exhibits 1 through 3, were admitted into evidence.)

MR. JIMINEZ: App Voices would move to have Mr. Barnes' prefiled direct testimony and summary entered into the record as though given orally from the stand, and have the exhibits attached to his prefiled direct testimony identified as prefiled Exhibits JRB-1 through JRB-4 moved into the record.

And, finally, App Voices would move that Mr. Barnes' supplemental testimony that was given from the stand be moved into the record.

COMMISSIONER KEMERAIT: Seeing no objection, your motion is allowed.

(Exhibits JRB-1 through JRB-4, were admitted into evidence.)

COMMISSIONER KEMERAIT: Mr. Barnes, thank for your testimony, and you may be excused.

THE WITNESS: Thank you, Commissioner Chair.

COMMISSIONER KEMERAIT: So our order of witnesses is now with the Public Staff, and the Public Staff my call its first witness.

MR. CREECH: Public Staff calls Fenge Zhang.

COMMISSIONER KEMERAIT: Good morning. Place your left hand on the Bible and raise your right hand.

Whereupon,

FENGE ZHANG,

having first been duly sworn, was examined and testified as follows:

COMMISSIONER KEMERAIT: Thank you.

DIRECT EXAMINATION BY MR. CREECH:

Q. Ms. Zhang, would please state your name, business address, and current position for the record?

A. Yes. My name is Fenge Zhang. I am a -- I'm a public utilities regulatory manager in Public Staff accounting division. The business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. Thank you. And are you aware that, on June 6, 2023, Public Staff witnesses Sonja Johnson and Iris Morgan prepared and caused to be prefiled in these dockets direct testimony consisting of 13 pages and 1 exhibit?

A. Yes.

Q. And you had knowledge that that testimony and exhibit were being prepared at that time, correct?

A. Uh-huh, yes.

Q. Are you aware of any changes or corrections to that prefiled direct testimony?

A. No, I don't.

Q. Okay. On July 6, 2023, did you adopt Ms. Johnson and Morgan's prefiled direct testimony exhibit as your own and, through counsel, move the

Commission to be substituted as a witness in place of Ms. Johnson and Morgan for the purposes of this hearing?

A. Yes, I did.

Q. Do you have any changes or corrections to that prefiled direct testimony?

A. No, I don't.

Q. If you were asked those same questions today while testifying from the witness stand, would your answers be the same?

A. Yes.

Q. On July 6, 2023, did you prepare and cause to be prefiled in these dockets testimony in support of settlement consisting of four pages, an appendix, and one exhibit?

A. Yes.

Q. Do you have any changes or corrections to your prefiled settlement testimony?

A. No.

Q. If you were asked those same questions today while testifying from the witness stand, would your answers be the same?

A. Yes.

MR. CREECH: Presiding Commissioner

Kemerait, at this time I move that prefiled direct testimony and settlement testimony and appendix of Public Staff witness Fenge Zhang be entered into the transcript at the appropriate time as if given orally from the stand, and that witness Zhang's direct and settlement testimony and exhibits respectfully entitled -- respectfully entitled Public Staff Accounting Exhibit 1 and Settlement Exhibit 1 be marked for identification as prefiled. Ms. Zhang is now available for cross-examination, if that's the case.

COMMISSIONER KEMERAIT: So the direct testimony filed on June 8, 2023, consisting of 13 pages and the settlement testimony filed on July 6, 2023, consisting of 14 pages will be copied into the record as if given orally from the stand. The two appendices attached to the direct testimony and the one exhibit attached to the direct testimony and the one appendix and the one exhibit attached to the settlement testimony will be marked for identification purposes as prefiled.

MR. CREECH: Thank you.

(Johnson and Morgan Public Staff Accounting Exhibit 1 and Public Staff

Zhang Settlement Exhibit 1, Schedule 1 and 2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled joint direct testimony and Appendices A and B of Sonja R. Johnson and Iris Morgan, Adopted by Fenge Zhang and prefiled settlement testimony and Appendix A of Fenge Zhang were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54 In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service DOCKET NO. E-34, SUB 55 In the Matter of Petition of Appalachian State University, d/b/a New River Light and Power Company for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	)	**JOINT TESTIMONY OF SONJA R. JOHNSON AND IRIS MORGAN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION**

June 6, 2023

Q. Ms. Johnson, please state your name, business address, and present position.

A. My name is Sonja R. Johnson. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Financial Manager for Natural Gas and Transportation with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. Briefly state your qualifications and duties.

A. My qualifications and duties are included in Appendix A.

Q. Ms. Morgan, please state your name, business address, and present position.

A. My name is Iris Morgan. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Public Utility Regulatory Analyst with the Accounting Division of the Public Staff.

Q. Briefly state your qualifications and duties.

A. My qualifications and duties are included in Appendix B.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present the accounting and ratemaking adjustments we are recommending, as well as those recommended by other Public Staff witnesses, as a result of the

Public Staff's investigation of the revenue, expenses, and rate base presented by Appalachian State University (ASU) d/b/a New River Light & Power Company (Company or NRLP) in support of its December 22, 2022 request for $4,624,749 in additional North Carolina retail revenue for the test year ended December 31, 2021 (test year), and updated by NRLP's filing on May 2, 2023, to $4,671,936. Additionally, we make recommendations regarding NRLP's petition for an Accounting Order for regulatory purposes, authorizing NRLP to establish regulatory assets and defer certain capital-related costs and tax expenses.

Q. What revenue increase is the Public Staff recommending?

A. Based on the level of rate base, revenue, and expenses annualized on December 31, 2021, with certain updates, the Public Staff is recommending an increase in annual operating revenue of $4,116,670.

Q. Please describe the scope of your investigation into the Company's filing.

A. Our investigation included a review of the application, testimony, exhibits, and other data filed by NRLP; an examination of the books and records for the test year; a review of NRLP's accounting, end-of-period and after-period adjustments to test year revenue, expenses, and rate base. The Public Staff also conducted extensive discovery in this matter, including the review of numerous responses provided by NRLP to the Public Staff's data requests.

Q. Please briefly describe the Public Staff's presentation of the issues in this case.

A. Each Public Staff witness will present testimony and exhibits supporting his or her position(s) and will recommend any appropriate adjustments to NRLP's proposed capital structure, return on equity, debt, rate base, and cost of service. Our exhibit reflects and summarizes these adjustments, as well as the adjustments we recommend.

Q. Please describe the organization of your exhibit.

A. Schedule 1 of Accounting Exhibit 1 presents a reconciliation of the difference between NRLP's requested increase of $4,671,936 as updated on May 2, 2023, and the Public Staff's recommended increase of $4,116,670.

Schedule 2 presents the Public Staff's adjusted original cost rate base. The adjustments made to NRLP's proposed level of rate base are summarized on Schedule 2-1, which are supported by backup schedules to Schedule 2-1.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are supported by backup schedules to Schedule 3-1.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required increase in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended increase shown at the bottom of Schedule 1.

Q. What adjustments to the Company's cost of service do you recommend?

A. We recommend adjustments in the following areas:

1. Accumulated depreciation and depreciation expense
2. Materials and supplies
3. Prepaid expenses
4. Allowance for funds used during construction (AFUDC)
5. Working capital
6. Non-utility expenses
7. Inflation

8. Regulatory fee and uncollectible expenses
9. Campus substation deferral
10. Unrelated Business Income Tax (UBIT) deferral

Q. What adjustments recommended by other Public Staff witnesses does your exhibit incorporate?

A. Our exhibit reflects the following adjustments recommended by other Public Staff witnesses:

1) The recommendations of Public Staff witness Hinton regarding the rate of return, capital structure, long-term debt, and customer growth and usage.

2) The recommendation of Public Staff witness Floyd regarding revenue apportionment and changes to NRLP's service regulations and rate schedules.

Q. Please describe your recommended adjustments.

A. Our adjustments are described below.

<u>Accumulated Depreciation and Depreciation Expense</u>

Q. Did the Public Staff annualize depreciation expense and accumulated depreciation?

A. The Public Staff has annualized overall depreciation expense at an end-of-period level. The Public Staff made corresponding adjustments to accumulated depreciation to annualize it and updated the per books accumulated depreciation. These updates and adjustments lead to a reduction (additional credit) in accumulated depreciation.

Materials and Supplies

Q. Please explain the Public Staff's adjustment to materials and supplies.

A. The Public Staff made an adjustment to reduce materials and supplies in rate base. The Public Staff utilized a thirteen-month average to calculate the prepaid expenses. This methodology is allowed by the Commission to reduce the variability of actual expenses throughout the course of a year. NRLP used actual expenses which resulted in an adjustment to rate base.

Prepaid Expenses

Q. Did the Public Staff make an adjustment to prepaid expenses?

A. Yes, the Public Staff utilized a thirteen-month average to calculate the prepaid expenses. This methodology is allowed by the Commission to reduce the variability of actual expenses throughout the course of a year. NRLP used actual expenses which resulted in an adjustment to rate base.

Allowance for Funds Used During Construction

Q. Please explain the Public Staff's adjustments to AFUDC for Substation, Laydown Yard, Supervisory Control and Data Acquisition (SCADA), Underground Conversion, and Warehouse expenditures.

A. The Public Staff adjusted the AFUDC calculation for Substation, Laydown Yard, SCADA, Underground Conversion, and Warehouse expenditures by using the Public Staff's recommended rate of return instead of the currently approved rate of return as NRLP has done.

Working Capital

Q. Please explain the Public Staff's adjustment to working capital.

A. The Public Staff calculated the working capital amount using lead-lag principles that take into account the difference between the estimated revenue and expense collection and payment lags, respectively. In our calculation, we have included: (1) 1/8 of total Operating and Maintenance (O&M) expense, less Purchased Power expense; and (2) the calculated working capital related to purchased power by multiplying the purchased power expense by estimated revenue lag days less estimated purchased-power-expense lag days. Subtracting the two calculations from NRLP's working capital resulted in an adjustment to rate base.

Non-Utility Expenses

Q. Please explain the Public Staff's adjustment to non-utility expenses.

A. The Public Staff included an adjustment to remove jobbing and contracting revenues and expenses, miscellaneous non-operating income, and other interest income, since these items are not part of providing electric utility service to customers.

Inflation

Q. Please explain the Public Staff's adjustment to inflation.

A. The Public Staff has inflated O&M expenses, not elsewhere set at an end-of-period cost rate, by one-half of a year, based on the CPI-U index.

Regulatory Fee and Uncollectibles

Q. Please explain your adjustment to regulatory fee and uncollectibles.

A. NRLP calculated the uncollectible and regulatory fee expenses as products of the total NRLP proposed revenue requirements and the percentage rate of the public utility regulatory fee. The Public Staff applied the same percentages to NRLP's total pro forma revenue under current rates and provided for uncollectible expenses and the regulatory fee on each of our pro forma adjustments to sales revenue. We also provided for uncollectible expenses and the regulatory fee on the recommended increase using the Commission's traditional "gross-up" method. The different methodologies used by NRLP and the Public Staff resulted in an adjustment to the regulatory fee and uncollectible expenses.

Campus Substation and UBIT deferrals

Q. Please explain the scope of the deferrals requested by the Company.

A. NRLP petitioned the Commission to issue an accounting order for regulatory accounting purposes, authorizing NRLP to establish a regulatory asset for the following:

1. The financing costs and incremental post-in-service depreciation expenses associated with a new campus substation that went into service in June 2022, as well as the undepreciated balance of the old campus substation that was retired from service.
2. Unrelated Business Income Tax (UBIT) expense resulting from revenue generated by electricity sold to the general public after June 2019.

Q. What are the total deferral amounts requested by the Company for each deferral request?

A. NRLP requested a regulatory asset in the amount of $443,904 for the campus substation, of which $323,378 is related to the new substation and $120,526 is related to the old substation. Additionally, NRLP requested $1,027,795 for UBIT deferral.

Q. Please explain the Public Staff's adjustment to the Company's campus substation deferral.

A. NRLP has two requests regarding the campus substation. First, NRLP requested amortization of the net book value as of October 27, 2021, of the old campus substation over a period of three years. NRLP also requested the depreciation and return for the new substation for the period from July 1, 2022, to July 31, 2023.

We have adjusted NRLP's request regarding the old campus substation to reflect the net book value as of July 31, 2023, since the depreciation expense for the plant was included in NRLP's rates, and therefore NRLP has recovered those costs until such time as new rates are approved on or about August 1, 2023. We have amortized the net book value of the old substation over a period of three years.

For the new substation, the Public Staff has calculated depreciation expense and return for a period of seven months and recommends amortizing the amount over the remaining useful life of the plant. We recommend a seven-month period to reflect the amount of depreciation and return NRLP would have been eligible to earn had NRLP filed its rate case in May 2023, as the 30-day notice filed in April 2023 indicated, with rates assumed to be effective February 1, 2023. The Public Staff believes ratepayers should not be held responsible for management's decisions regarding the significantly delayed filing of the rate case.

Q. Please explain the Public Staff's adjustment to UBIT deferral requested by the Company.

A. Although NRLP characterizes the tax liability for UBIT from past years as "unexpected," the Public Staff does not believe the liability was unexpected. ASU relied on initial advice that was not in line with the expectations of the IRS, which made the taxes a known issue to NRLP.

In addition to the request not meeting the first prong of the two-prong test for deferrals, NRLP knew the amount of the tax in 2019, but did not make a request for deferral until 2022. A deferral mechanism request by NRLP now, for a UBIT tax expense burden which was known in 2019, is not timely and should not be the burden of the ratepayer.

Finally, in its deferral request, NRLP included quarterly estimated taxes it had calculated and paid. When the utility files its annual tax returns, they would true up the additional tax liability or receive a refund from the IRS for the overage. Our detailed review of the data request and teleconference call responses provided by NRLP indicates that ASU (including NRLP and other ASU entities, such as the bookstore) experienced net losses in the fiscal years of 2021 and 2022, resulting in a zero UBIT tax liability for 2021 and 2022, which is not reflected in the deferral schedule included in NRLP's application. Therefore, the estimated costs included in NRLP's request do not present an accurate amount of NRLP's actual tax liability. Since the requested deferral amounts have not been updated for the actual tax liability that NRLP has experienced, the deferral amount requested by NRLP is not accurate.

Based upon all of the above, the Public Staff recommends the deferral request for UBIT not be approved, and we removed the associated impacts to rate base and operating expenses.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A
Page 1 of 2

QUALIFICATIONS AND EXPERIENCE

SONJA R. JOHNSON

I am a graduate of North Carolina State University with a Bachelor of Science and Master of Science degree in Accounting. I was initially an employee of the Public Staff from December 2002 until May 2004 and rejoined the Public Staff in January 2006. I became the Accounting Division's Manager for Natural Gas and Transportation in May 2022.

As an Accounting Manager, I am responsible for the performance and supervision of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

Since initially joining the Public Staff in December 2002, I have filed testimony or affidavits in several water and sewer general rate cases. I have also filed testimony in applications for certificates of public convenience and necessity to construct water and sewer systems and noncontiguous extension of existing systems. My experience also includes filing affidavits in several fuel clause rate cases and Renewable Energy and Energy Efficiency Portfolio Standard (REPS) cost recovery cases for the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Virginia Electric and Power Company d/b/a Dominion North Carolina Power.

While away from the Public Staff, I was employed by Clifton Gunderson, LLP. My duties included the performance of cost report audits of nursing homes, hospitals, federally qualified health centers, intermediate care facilities for the mentally handicapped, residential treatment centers and health centers.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

IRIS MORGAN

I graduated from North Carolina Wesleyan College with a Bachelor of Science Degree in Accounting and Business Administration in 2007. In addition, I graduated from the Keller Graduate School of Management with a Master of Accounting and Financial Management (2011), a Master of Business Administration (2013), and a Master of Public Administration (2014).

Prior to joining the Public Staff, I was employed by WorldCom, Inc., as a CORE Analyst. My duties included providing customer service support and addressing customer billing and reporting requirements. I joined the Public Staff in September 2002 as an Administrative Assistant.

In 2006, I was promoted to the position of Consumer Services Complaint Analyst, where I resolved numerous consumer complaints and performed utility reporting analysis. After completion of my accounting degree, I was promoted to the position of Public Staff Accountant in December 2008.

I have performed audits and filed testimony and exhibits in several water rate cases and assisted in investigations addressing a wide range of topics and issues related to the water, electric, and gas industries.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54	
In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service	**SETTLEMENT TESTIMONY OF FENGE ZHANG PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION**
DOCKET NO. E-34, SUB 55	
In the Matter of Petition of Appalachian State University, d/b/a New River Light and Power Company for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	

July 6, 2023

Q. Please state your name, business address, and present position.

A. My name is Fenge Zhang. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Public Utilities Regulatory Manager with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. Please provide your qualifications and experience.

A. My qualifications and experience are provided in Appendix A.

Q. What is the purpose of your settlement testimony in this proceeding?

A. The purpose of my testimony is to support the Agreement and Stipulation of Settlement dated July 5, 2023 (Stipulation), between New River Light and Power Company (NRLP or the Company) and the Public Staff (Stipulating Parties).

Q. Please briefly describe the stipulation.

A. The Stipulation sets forth agreement between the Stipulating Parties in the following areas:

1. The weighted overall rate of return, including the capital structure, debt cost rate, and cost of equity;
2. The overall recommended base revenue increase;
3. Campus Substation deferral;
4. Unrelated Business Income Tax (UBIT) deferral;

5. Rate case expense; and
6. Working together regarding the calculation of revenue requirement in the next general rate case.

The details of the agreements in these areas are set forth in the body of the Stipulation.

Q. What benefits does the Stipulation provide for ratepayers?

A. From the perspective of the Public Staff, the most important benefits provided by the Stipulation are as follows:

a) A reduction in the $4.672 million base non-fuel revenue increase requested in the Company's April 10, 2023 supplemental filing, resulting from the adjustments agreed to by the Stipulating Parties; and

b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. Have the Stipulating Parties agreed on the establishment and amortization of deferrals for the Campus Substation and UBIT?

A. Yes. As detailed in the Stipulation, the Stipulating Parties have agreed to the establishment of regulatory assets for the old campus substation, new campus substation, and UBIT. Additionally, as detailed in the Stipulation, the Stipulating Parties have also agreed to the regulatory liability treatment for over-amortizations regarding these deferrals.

Q. Would you briefly describe the Public Staff's presentation of the revenue requirement aspects of the Stipulation?

A. Yes. The attached Settlement Exhibit 1 sets forth the accounting and ratemaking adjustments, and the resulting rate base, net operating income, return, and rate increase, to which NRLP and the Public Staff have agreed.

Q. Does this conclude your settlement testimony?

A. Yes.

QUALIFICATIONS AND EXPERIENCE

FENGE ZHANG

I graduated from North Carolina State University with a Bachelor of Science degree and a master's degree in accounting. I am a Certified Public Accountant. I am the Public Utility Regulatory Manager in the Accounting Division Public Staff of North Carolina Utilities Commission.

As a Public Utilities Regulatory Manager with the Accounting Division of the Public Staff, I am responsible for the performance, supervision, and management of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

I was first employed by the Public Staff in March 2012. Then in 2016, I began employment with the Commission until I returned to Public Staff employment in May 2022. Throughout this time, I have been involved in audit and review of various topics related to the regulated telephone, water, sewer, electric and natural gas industries, including the most recent general rate cases for Carolina Water Service, Inc. of North Carolina in 2022 and Aqua North Carolina, Inc. in 2022. I have also filed and assisted with the Demand Side Management and Energy Efficiency riders, electric fuel rider cases, gas annual reviews, and lead lag studies. Most recently, I filed an affidavit on Duke Energy Progress, LLC's 2022 fuel proceeding in Docket No. E-2, Sub 1292.

MR. CREECH: Thank you. Ms. Zhang is available for cross examination.

COMMISSIONER KEMERAIT: Beginning with Appalachian Voices?

MR. JIMINEZ: Nothing from App Voices.

COMMISSIONER KEMERAIT: Okay. From New River?

MR. STYERS: No cross examination.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. So, Ms. Zhang, the Commission has -- Commission staff has several questions for you.

First of all, relating to the Stipulation. On page 4 of the Stipulation, Item 16 that relates to the accounting adjustments, did the parties -- and I can wait until you get there.

A. Yes, I'm here.

Q. Okay. Did the parties intend for the agreed-upon deferral amount of $364,646 to be repeated the next two times in this item where the $346,646 is stated? In other words, are there two typos? Should all of the numbers in this paragraph be the $364,646?

A. Yes.

Q. Okay. So there are two typos; is that correct?

A. Yes. I think we addressed on the preliminary matter at that time by New River.

Q. Okay. And then a follow-up to that question.

Was the agreed-upon amount of the $364,646, the result of a calculation?

For example, did the parties agree to the recovery of the UBIT for certain years or is the $346,646 [sic] an agreed-upon percentage of the total amount that the Company requested?

A. That -- these of $364,646 is the estimate tax liability for the fiscal year 2023. Yeah.

Q. And that was agreed upon with the Company; is that correct?

A. Yes. We settled with that amount.

Q. Okay. And then did the Public Staff agree with the revised calculation of the amount of $931,544 that is reflected in the Jamison Rebuttal Exhibit Number 2?

A. Which -- do you mind pointing me to the page? I may not have --

Q. Okay. So it would be under Rebuttal Exhibit 2. Perhaps your attorneys might have that to provide to you.

MR. CREECH: May I approach?

COMMISSIONER KEMERAIT: Yes, you may.

THE WITNESS: So which line are you referring to?

Q. I don't have the line. I just have it as the Exhibit Number 2.

A. Okay.

(Witness peruses document.)

So I have to check, because I'm not sure this one -- is this one the update provided by the Company? If so, yes, it should be the last -- you can see the fiscal year 2023, there was a sum-up. It should be -- let me see.

(Witness peruses document.)

So you see the last 10 lines, those -- sum it together, except the refund. So the title on the second to the last column, the first, like, fiscal -- FY '23, all those sum up together.

Those are the estimate, because the Company had to pay -- each quarter had to pay the estimate tax based on their estimated tax liability. So they provide that to us on -- upon our request at that time.

Q. And to make sure I understand you correctly, is the total that you're talking about, is that the approximately $931,000 amount?

A. No.
Q. What amount are you speaking to then?
A. The total should be the $364,646; so if you sum up the last -- like the line -- last 10 row, but except the refund from the fiscal year 2022. Title as FY '23, first, second, third, fourth quarter. So those sum up, you will be getting the 364.
Q. Okay. Thank you. And then a follow-up question -- we just want to make sure we're clear on the record.
Is the Company and the Public Staff -- are you agreeing to not have -- to having no unamortized balance and the rate base related to the UBIT deferral?
A. The unamortized balance you state in the rate base. So like, let's say because the amortized over three years, so after first year amortization, remaining two years is included in the rate base.
Q. So it will be the un- -- to make sure we're clear on this, the unamortized balance will, in fact, be the position of the parties -- the Public Staff and the Company -- is it will be included in the rate base?
A. Yes.
Q. And then moving on to the AFUDC rate. All right. I'm looking at rebuttal testimony of New

River's witness Halley, and this will be on page 24. And I can read what -- I can summarize what he stated, and then if you need to see it, one of your attorneys could provide his testimony.

A. Okay. Thank you.

Q. On page 24, which would be lines 8 through 12, in his rebuttal testimony, he states that, The Public Staff has proposed to calculate all of New River's AFUDC based on the Public Staff's proposed rate of return rather than New River's currently approved rate of return.

Can you explain how this issue was resolved between Public Staff and the Company and the Stipulation?

A. Yes. So in the Stipulation, we have all the settled with the approved rate, which will be the 6.525 percent of the ROR. So we have resolved that, I believe.

Q. I'm sorry, can you repeat your answer, so I can make sure I understand?

A. Okay. So in the Settlement, we are using the method based on the prior rate case, and that is agreed upon by the Company. So when we calculate the AFUDC rate, that is based on the ROR of 6.525, I believe, but

I can -- let me check my schedule. I believe that's the --

(Witness peruses document.)

Yes. So based on the approved last rate case ROR, and the math that we're using is based on the prior case. And the Company did not object that in the last rate case, the math that the Public Staff calculated.

Q. Okay. So the Company agreed to the use of the currently approved rate of return in the stipulation?

A. Not the currently approved.

Q. The past rate case?

A. Yes. The ROR will be the last rate case.

Q. And then can you explain the Public Staff's rationale for using the proposed return, rather than the Commission-approved return to calculate the AFUDC? Is this a change in the Public Staff's policy, and can you provide the Public Staff's position about this?

A. So I -- because I did not work on the last rate case, so I don't know what is actually used on the last rate case, the approved ROR or the proposed ROR. So if you don't mind, I can file a late-filed exhibit for the response on that piece.

Q. That would be fine, to file a late-filed exhibit, but this question came from the Commission staff. But I think that your answer was that the use was -- the return was based upon the -- not the proposed rate of return, but the past rate case rate of return; is that correct?

So my question was probably not applicable, since we're talking about use of the rate of return in the last rate case; is that correct?

A. Yes. Because AFUDC is calculated for the plant in service at the time, like from the construction until they place in service. So in this rate case, we settled with, like, it's more appropriate to use the last approved ROR, because that capital investment is not decided on this rate case. So we settled with that number.

Q. Okay. So my last question was actually not reflective of the answer that you previously provided. So I don't believe that we will need a late-filed exhibit.

A. Okay. Thank you.

COMMISSIONER KEMERAIT: Any questions from the Commission? Chair Mitchell?

EXAMINATION BY CHAIR MITCHELL:

Q. All right, Ms. Zhang, I have a few for you.

Can you look at your settlement testimony, Exhibit 1, Schedule 2, please, ma'am? And just let me know when you get there.

A. Yes.

Q. Okay. I'm interested in lines 9 and 10, specifically. I see the Public Staff made adjustments there, and so I want you to walk me through those adjustments.

But before you do that, will you explain -- explain what each of those line items describes; the type of costs those line items describe?

A. Okay. Are you talking about line nine and line ten, the cash working capital?

Q. Yes.

A. Okay. So those adjustment has two parts. One part is the calculation on the cash working capital using the 1/8 of the O&M costs.

COURT REPORTER: I'm sorry, you said 1/8?

THE WITNESS: Yes, 1/8. One divided by eight. And then there's a second part of the Public Staff adjustment is the -- up to the 2022 update. So those are based on -- so what we do is based on the actual 2022 update amount of O&M, and calculate our cash working capital they need for the Company, and that amount we settle with the Company, and then compare that to the application amount. So that's the column B you see, that's the total adjustment.

Q. Okay. So thank you for that clarification. I just want to make sure I understand you, so I'm gonna explain how I understand, and you tell me if I'm right or wrong.

So those two adjustments, the Public Staff adjustments shown on lines 9 and 10, simply correct the amounts to get them to 1/8 -- 1/8 cash working capital standard, so to speak, and then what was the second adjustment?

A. Second, because --

Q. Through the adjustment?

A. Yeah, update.

Q. Through the update period.

But the Public Staff didn't make any substantive adjustments to those expenses?

A. No, because they just base on 1/8 of the O&M, so they're using the formula. And then for the purchase power, they would have the lead lag day to calculate. So for the purchase power, that line 9, that line is the lead day or the lag day, based on the purchase power they receive the revenue or the cost to pay, so I believe it's about 12.5 days.

Q. Okay.

A. I have to check my schedule if you need it.

Q. Okay. All right. That's sufficient. I appreciate that.

Did you have an opportunity to review any of the Company's exhibits filed with settlement testimony?

A. Some degree.

Q. Okay. Well, I'll hold my questions for the Company then. That's all I have for you. Thank you, ma'am.

A. Okay. Thank you.

COMMISSIONER KEMERAIT: So that is all for the Commission questions. Thank you. And now we'll move to questions on Commission questions.

MR. DROOZ: None from New River.

MR. JIMINEZ: None from App Voices.

MS. LaPLACA: None from me.

MR. CREECH: No. Thank you.

COMMISSIONER KEMERAIT: Well, that is all. So thank you for your testimony.

Are there any motions the parties would like to make?

MR. CREECH: Yes, please. Presiding Commissioner Kemerait, the Public Staff would move that the exhibit attached to the prefiled direct testimony, as adopted by Ms. Zhang, and the exhibit attached to the prefiled settlement testimony of Ms. Zhang entered into the record and marked for identification as premarked.

COMMISSIONER KEMERAIT: Seeing no objection, the motion is allowed.

And, Ms. Zhang, you may be excused.

THE WITNESS: Thank you.

(Johnson and Morgan Public Staff
Accounting Exhibit 1 and Public Staff
Zhang Settlement Exhibit 1, Schedule 1
and 2 were admitted into evidence.)

COMMISSIONER KEMERAIT: And I believe that the next order of witness is Mr. McLawhorn.

MR. FELLING: Thank you, presiding Commissioner Kemerait. We would call Mr. McLawhorn to the stand.

COMMISSIONER KEMERAIT: Good morning.

THE WITNESS: Good morning.

COMMISSIONER KEMERAIT: Place your left hand on the Bible and raise your right hand.

Whereupon,

JAMES MCLAWHORN,

having first been duly sworn, was examined and testified as follows:

COMMISSIONER KEMERAIT: Thank you.

DIRECT EXAMINATION BY MR. FELLING:

Q. Mr. McLawhorn, would you please state your name, your business address, and current position for the record, please?

A. James McLawhorn, 430 North Salisbury Street, Raleigh. I'm the director of Public Staff's energy division.

Q. Are you aware that on June 6, 2023, Public Staff witness Jack Floyd prepared and caused to be prefiled in these dockets direct testimony consisting of 29 pages, an appendix, and one exhibit?

A. Yes.

Q. And was that testimony and exhibit prepared with your knowledge and under your supervision as Mr. Floyd's supervisor at the time?

A. Yes, it was.

Q. And are you aware of any changes or

corrections to that prefiled direct testimony?
A. No, I am not.
Q. And on June 30, 2023, did you adopt Mr. Floyd's prefiled direct testimony and exhibit as your own, and through counsel, move the Commission to be substituted as a witness in place of Mr. Floyd for the purposes of this hearing?
A. Yes.
Q. And if you were asked those same questions today while testifying at hearing from the witness stand, would your answers be the same?
A. Yes, they would.
Q. And on July 6, 2023, did you prepare and cause to be prefiled in these dockets testimony in support of the settlement consisting of six pages?
A. Yes.
Q. Do you have any changes or corrections to that prefiled settlement testimony?
A. No.
Q. And if you were asked the same questions today while testifying from the witness stand, would your answers be the same?
A. Yes, they would.
MR. FELLING: Presiding Commissioner

Kemerait, at this time, I would move that the prefiled direct testimony and appendix and settlement testimony of Public Staff witness James McLawhorn be entered into the transcript at the appropriate time as if given orally from the stand and that Mr. -- that McLawhorn Exhibit 1 be marked for identification as prefiled.

COMMISSIONER KEMERAIT: So the direct testimony of Mr. McLawhorn filed on June 8, 2023, consisting of 29 pages, will be copied into the record as if given orally from the stand. The one appendix and one exhibit that was attached to the direct testimony will be marked for identification purposes as prefiled, and his settlement testimony filed on July 6th of 2023, consisting of six pages will also be copied into the record as if given orally from the stand.

MR. FELLING: Thank you.

(McLawhorn Exhibit 1 was identified as it was marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A of James McLawhorn and prefiled settlement testimony of James McLawhorn were copied

into the record as if given orally from
the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54 In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service DOCKET NO. E-34, Sub 55 In the Matter of Petition of Appalachian State University d/b/a New River Light and Power Company for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	**TESTIMONY OF JAMES S. MCLAWHORN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION**

June 30, 2023

Q. Please state your name, business address, and present position.

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the director of the Energy Division of the Public Staff – North Carolina Utilities Commission (Public Staff),

Q. Briefly state your qualifications and duties.

A. My qualifications and duties are attached as Appendix A.

Q. What is the mission of the Public Staff?

A. The Public Staff represents the interests and concerns of the using and consuming public in all public utility matters that come before the North Carolina Utilities Commission (the Commission). Pursuant to N.C. Gen. Stat. § 62-15(d), it is the Public Staff's duty and responsibility to review, investigate, and make appropriate recommendations to the Commission with respect to the following utility matters: (1) retail rates charged, service furnished, and complaints filed, regardless of retail customer class; (2) applications for certificates of public convenience and necessity; (3) transfers of franchises, mergers, consolidations, and combinations of public utilities; and (4) contracts of public utilities with affiliates or subsidiaries. The Public Staff is also responsible for appearing before state and federal courts and agencies in matters affecting public utility service.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to set forth the Public Staff's findings and recommendations resulting from our examination of the Application of Appalachian State University, d/b/a New River Light & Power Company (NRLP) in Docket No. E-34, Sub 54 filed on December 22, 2022, (Application) for the test year ended December 31, 2021 (Test Year). More specifically, my testimony addresses the following items contained in NRLP's Application:

- Various capital investments associated with a replacement substation, a renovated and expanded laydown yard, a warehouse expansion and renovation, a new supervisory control and data acquisition (SCADA) system, and the undergrounding of distribution circuits in certain residential subdivisions.
- The cost-of-service study (COSS) used in this case.
- Rates and rate schedules, including NRLP's proposed Net Billing Rider (Schedule NBC); Purchased Power for Renewable Energy Facilities (Buy-All-Sell-All) (Schedule PPR); and Interruptible Service Rider (Schedule IR); and

- Customer Class revenue apportionment and NRLP's proposed two-year phase-in of its requested revenue increase.

Q. Briefly explain the scope of your investigation regarding NRLP's Application.

A. The scope of my investigation consisted of a review of:

- NRLP's application;
- the COSS used in this proceeding to allocate costs among the various customer classes based upon appropriate cost causation principles, which served as the foundation for the utility's various rate schedules; and
- the conditions of service that serve to produce the requested revenue requirement reflected in NRLP's proposed base rate charges.

Finally, my investigation also included an analysis of the need for, and costs associated with, various NRLP capital investments made to provide adequate utility service included for recovery in this case.

Q. Are you providing any exhibits with your testimony?

A. Yes. McLawhorn Exhibit 1 provides the Public Staff's recommended revenue apportionment.

I. Capital Investments

Q. Please discuss the Public Staff's review of the large capital investments made by NRLP that are included for recovery in this rate case.

A. NRLP witness Edmond C. Miller identified five major capital projects that NRLP completed subsequent to its last rate case in Docket No. E-34, Sub 46 (Sub 46 case). Those projects are: (1) a new campus substation; (2) a new SCADA system; (3) renovation and expansion of a warehouse and office building; (4) reconstruction of a laydown yard for storage of large equipment and materials; and (5) undergrounding of certain distribution lines.

The Public Staff's investigation of these capital expenditures included a review of the costs (including bid solicitations); the basis for the expenditures; how these projects would improve the customer service; and how they would serve as a predicate for future new opportunities for enhanced customer services and efficiencies. I address each project need below:

1. <u>The new substation, which serves the main campus of Appalachian State University,</u> is the last of five NRLP substations to be converted to a new voltage delivery level as required by Blue Ridge Electric Membership Corporation (BREMCO), from whom NRLP purchases its transmission service requirements.

The conversion represents a more than 10-year process of converting each NRLP substation to receive power at 100 kilovolts (kV) from BREMCO's transmission system. In addition, the new substation includes new physical security features.

2. The recent implementation of an advanced metering infrastructure (AMI) network, as discussed in the Sub 46 Case, required a <u>new SCADA system</u> to allow NRLP to monitor customer usage and system conditions and allow for more prompt response to those system conditions. The combined AMI and SCADA systems also allow customers to have more involvement in their electricity purchases from the utility. While these capabilities are still evolving, the utility is now positioned to begin looking into and implementing new opportunities to assist customers with more energy efficiency (EE) measures, demand response, and time-of-use rate designs, all of which could help reduce or shift overall peak demand and energy consumption.
3. <u>The renovation and expansion of the warehouse</u> was necessary to improve employee access and efficiency, upgrade workspace, update environmental systems, shelter equipment from the weather, and accommodate greater storage for equipment and supplies.

4. <u>The existing laydown yard</u> was completely renovated to provide a safer and more efficient means of accessing large equipment and materials.
5. <u>The undergrounding of distribution service</u> was completed in response to chronic outages in some of NRLP's older residential neighborhoods. One customer at the public hearing on May 23, 2022, testified to the improved service quality experienced from the undergrounding projects.

Q. What is your recommendation regarding these capital investments?

A. Based on the Public Staff's review and in-person inspection of the facilities associated with each of the capital investments discussed above, I believe each was necessary and constructed in a reasonable and prudent manner. I do not object to their inclusion in rate base in this case. Public Staff Accounting witnesses Sonja R. Johnson and Iris Morgan address the treatment of the remaining book value of the old substation.

<u>II. Cost of Service Study</u>

Q. Have you reviewed NRLP's COSS in this proceeding?

A. Yes.

Q. What is the purpose of the COSS?

A. The purpose of any COSS is to measure and determine the appropriate share of revenues, expenses, and plant related to the provision of electric service that is the responsibility of individual jurisdictions and customer classes. Typically, these studies are developed based on billing determinant data such as number of customers, direct-metered energy sales (kWh), and registered demand (kW). When direct usage data is not available, load research is utilized. Cost-of-service studies use this load research data as the basis for assigning or allocating the system and jurisdictional revenues, expenses, and plant to the various customer classes. Development of the COSS is the first step in determining the appropriateness of cost-based rates for electric service.

Q. Please explain NRLP's COSS in this proceeding.

A. In the Sub 46 case, the Commission ordered NRLP to update all load data in its COSS to incorporate a full year of data collected from its AMI system and file an updated COSS by the end of June 2019. NRLP filed its updated COSS on June 18, 2019.

In the present case, NRLP has used the data available from its AMI system to develop the demand- and energy-related inputs in the COSS, along with other load data, which is used to develop an allocation of costs to the various customer classes. NRLP Exhibit

REH-14 represents the COSS that was used to develop various allocation factors to apportion revenues, expenses, and rate base to the various customer classes. As a distribution-only utility,[1] NRLP does not have production costs similar to other investor-owned utilities. Production-related capacity costs are recovered pursuant to the terms of the purchase power agreement (PPA) with NRLP's provider, Carolina Power Partners (CPP). NRLP pays Duke Energy Carolinas, LLC (DEC), and BREMCO, for power delivery services from CPP to NRLP.[2]

NRLP uses class coincident peak data to allocate capacity-related costs associated with the PPA. DEC-related PPA transmission costs are allocated using DEC's transmission peak demand data. BREMCO's power delivery costs are allocated using BREMCO's coincident peak demand data. NRLP's distribution-related costs are allocated using NRLP's distribution peak demand data. Customer-related costs are allocated based on customer data weighted on the kW demands of each class.

Purchased power costs represent approximately 71% of NRLP's total expenses related to the provision of utility service. The

[1] NRLP purchases 100% of its power supply requirements at wholesale.

[2] CPP interconnects directly with DEC, which delivers power to BREMCO; BREMCO interconnects directly with NRLP.

remaining 29% of expenses are related to operating and maintaining the local distribution system, customer accounting, and general administration of the utility. In recent months, NRLP has experienced volatility in its purchased power costs, and the Commission addressed that volatility by allowing NRLP to update its purchased power adjustment rider more frequently than annually to mitigate the potential for rate shock associated with significant annual under-collections.[3]

Q. Does the Public Staff have any comments or recommendations related to the COSS in this proceeding?

A. No. NRLP has complied with the Commission's Sub 46 case order through the COSS filed in this proceeding. As evidenced through customer comments at the May 23, 2023, public hearing in this case, many NRLP customers would like to see more opportunities for customer-owned distributed energy resources directly connected to its distribution system. As customers begin to demand more options for electric vehicle (EV) charging, along with the ability to adopt and potentially own renewable energy resources, the COSS and necessary data to properly evaluate how customers are using and imposing costs on the NRLP system will become more paramount in

[3] See Order Approving Mid-Year Supplemental Purchased Power Adjustment dated July 26, 2022, in Docket No. E-34, Sub 53.

future rate cases. As a distribution-only electric utility, NRLP, as well as the Public Staff and the Commission, will need to devote even greater focus to the question of cost causation.

III. Rate Schedules

Q. Please discuss the proposed changes to the NRLP rate schedules.

A. NRLP is requesting several changes in this case to its portfolio of rate schedules. The more noteworthy changes include:

1. Closure of Schedule GLH;
2. Shift in cost recovery from an energy charge to a new NRLP Distribution Charge and Wholesale Power Supply Charge;
3. New net billing rider Schedule NBR;
4. New buy-all-sell-all (BASA) Schedule PPR; and,
5. New interruptible rider Schedule IR.

Closure of Schedule GLH – This schedule was promulgated in the Sub 46 case on the premise of offering high load factor non-residential customers another rate option. While the premise was sound, no customers have expressed interest in this schedule to date. NLRP witness Randall E. Halley's testimony and responses to discovery also indicate that there is little difference in load shapes between Schedules GL and GLH. This likely limits the opportunities for high load factor customers to save money without making significant changes to their consumption. The Public Staff does not object to this request to close Schedule GLH.

New NRLP Distribution Charge and Wholesale Power Supply Charge – NRLP has proposed to separate the energy charges contained in its rate schedules into two separate charges in order to better identify and recover the costs associated with its distribution system from costs associated with the PPA. This separation takes the current energy charges in Schedules R and G, and the demand and energy charges in Schedule GL, and isolates the recovery of distribution-related costs from costs associated with the energy purchased through the PPA. Schedule A (ASU Campus Service) already distinguishes distribution-related costs from PPA costs in its structure.

The Public Staff reviewed both the COSS and the calculations behind this change. As stated by NRLP witness Halley in his testimony, this rather significant structural change in rates is needed to better distinguish distribution-related costs from PPA costs. The proposed structural change will make all of NRLP's rate schedules structurally consistent and should aid the utility in better understanding cost causation going forward. Having a clearer understanding of cost causation will allow NRLP to more appropriately respond to the cross-subsidization of customer classes. This change is crucial given NRLP's proposed Schedule NBR (Net Billing Rider).

Schedule NBR – NRLP is proposing a new option for customers who have behind-the-meter (BTM) solar photovoltaic (PV) generation assets connected to their electric service. The only current option available to customers with BTM distributed PV generation is Schedule SPP, which is structured similarly to a BASA rate schedule based on the Public Utilities Regulatory Policy Act (PURPA). 16 U.S.C. § 2611 *et. sec.*

Witness Halley states that the new Schedule NBR is being developed in a manner that follows the criteria established by N. C. Gen. Stat. § 62.126.4. (S.L. 2017-192, or HB 589), which requires the Commission to "…ensure that the net metering retail customer pays its full fixed cost of service" and requires a grandfathering of existing customers already being served under a current net metering rate schedule. Schedule NBR will be available to customers on Schedules R, G, and GL and limited to: (1) residential PV systems of less than 20-kilowatt (kW) capacity; and (2) non-residential systems of less than 1,000 kW capacity. Schedule NBR also incorporates a January 1 annual resetting of energy credits that have accrued over the previous 12-month period. The reset will not impact the basic facilities charges or demand charges as applicable in

Schedules R, G, and GL. Schedule NBR also obligates participating customers to pay a Standby Supplemental Charge (SSC) that is intended to recover some of the fixed costs of distribution-related system costs.

The Public Staff reviewed the NRLP's proposal and finds that it makes a reasonable effort toward compliance with HB 589. In addition, Schedule NBR is similar to the net metering tariffs recently approved by the Commission for DEC and Duke Energy Progress, LLC (DEP) (collectively Duke).[4] NRLP's proposed SSC are similar to Duke's non-by-passable charges and grid access fees in that both are intended to recover fixed costs not readily avoided by the BTM generation. I reviewed the calculations associated with the proposed $6.17/kW SSC. The value of the SSC is based on an allocation of the transmission- and distribution-related costs associated with the delivery of energy from the PPA that are not avoided.

One notable difference between Duke's net metering proposal and Schedule NBR is the excess energy credit resetting process. Duke's tariffs incorporate a monthly resetting process. Schedule NBR has an annual resetting process. While a monthly process is preferable because it would reduce cross-subsidization between participants on

[4] See Order Approving Revised Net Metering Tariffs, March 23, 2023, Docket No. E-100, Sub 180.

Schedule NBR and non-participants, I am not recommending monthly resetting for NRLP at this time for the following reasons. First, the structure of the various contracts between NRLP and CPP for purchased power, DEC for transmission services, and BREMCO for both transmission and distribution services and how those contracts use multiple coincident peaks to determine the costs of energy are large drivers of cost causation. At this time, it is unclear how Schedule NBR will impact BTM participation and the various coincident peaks that impact total purchased power costs. This concern leads to a second area of uncertainty around how annual versus monthly resetting would impact the calculation of the SSC, which is mainly driven by the influence of the coincident peaks. Third, this proposal represents NRLP's first net metering/billing tariff. Customers testifying at the public hearing expressed concerns around net metering/billing in general. I believe that monthly resetting could exacerbate those concerns by limiting benefits to participants who invest in solar PV generation. Finally, NRLP is a winter-peaking utility. Unlike Duke who was a summer-peaking utility when net metering was initiated in the early 2000s, annual resetting would provide some added benefit to participating customers by taking the excess energy produced during higher producing summer periods and using it to offset winter consumption.

The Public Staff supports NRLP's proposal and believes it is appropriate to maintain an annual resetting and the SSC in the tariff design. The Public Staff also recommends that:

1. NRLP closely monitor the credits accumulated, consumption patterns, revenues, and costs related to the proposed Schedule NBR and file an annual report of net metering/billing activities by March 31 of each year;
2. Schedule NBR allow participants to retain ownership of any renewable energy credits from power generation by their systems. As a result, proposed Schedule NBR should be amended to include the following statement: <u>"Any renewable energy credits (RECs) associated with electricity delivered to the grid by the Customer under Schedule NBR shall be retained by the Customer."</u>
3. The Commission revisit the proposed design of Schedule NBR in five years and re-evaluate the energy resetting process and the SSC at that time.

<u>Schedule PPR</u> – Similar to Schedule NBR, NRLP is proposing another BTM generation tariff that will be available to customers with solar PV generation connected in parallel to NRLP's system. Customers with less than 1 megawatt (MW) of PV capacity and not on one of the Schedule SPP tariffs (PURPA schedules) will be able

to participate. Schedule PPR is structured as a BASA tariff that obligates the participant to sell all of the energy produced to NRLP at a fixed energy credit.

The Public Staff has reviewed the supporting calculations associated with the energy credit. NRLP stated in discovery that the original filing calculated the credit based only on residential class costs. A revised credit that is reflective of total system costs would be more appropriate.

Similar to Schedule NBR, proposed Schedule PPR does not address the ownership of RECs resulting from renewable energy resources. Under Schedule PPR, NRLP is compensating customer-owned renewable generation at the full avoided costs rate, which does not include costs associated with renewable energy. This makes Schedule PPR effectively identical to Schedule NBR in terms of REC ownership.

The Public Staff also supports NRLP's proposed Schedule PPR and believes it provides another option for customer-owned renewable energy generation. Similar to Schedule NBR, the Public Staff believes the effects of BTM generation subscribed to Schedule PPR could impact the COSS in future rate cases and recommends that:

1. NRLP closely monitor the credits paid to participants for the energy they produce, revenues received from participants for

utility service, generation and consumption patterns, and costs related to the proposed Schedule PPR and file an annual report of activities by March 31 of each year;

2. Proposed Schedule NBR be amended to include the following statement: "Any renewable energy credits (RECs) associated with electricity delivered to the grid by the customer under Schedule PPR shall be retained by the Customer."
3. The Commission revisit the proposed design of Schedule PPR in five years;
4. NRLP revise the Schedule PPR energy credit to reflect total system costs in its rebuttal testimony; and,
5. The energy credit paid pursuant to Schedule PPR be updated and revised consistent with NRLP's approved PURPA avoided cost proceeding.

Schedule IR – NRLP is proposing a new interruptible rate schedule targeted to large, high load factor non-residential customers with at least 2 MW of load and with the ability to curtail 75% of that load when called upon to do so. Schedule IR is structured such that the participant would earn a credit of $14.26 per kW of load reduced, if the curtailment coincides with NRLP's monthly coincident peak.

NRLP stated in response to discovery that the utility has been approached by potential non-residential customers about such a demand response program. While no such customers have either located in NRLP's service territory or actively petitioned NRLP for such a program, NRLP wants to be prepared to offer such a program to prospective participants. NRLP also stated in discovery that it would provide as much as three-day's advance notice of the coincident peak, and if the customer were to miss the coincident peak, no penalty would be assessed. Furthermore, credits would only be paid based on the average two-hour load prior to and after the announced curtailment period.

The Public Staff reviewed the proposal, the supporting calculations for the curtailment credit, and the terms and conditions of Schedule IR. The credit is based on the contract demand charge associated with the purchased power agreement plus an adjustment for system losses. As designed, if the curtailment reduces NRLP's monthly coincident peak, the participant will receive the bulk of the benefit (cost savings). However, the overall system would also receive some benefit from reduced purchased power costs. Intangible benefits would also accrue to the community in the form of increased economic activity.

With respect to the terms and conditions contained in the language of the tariff included in Exhibit B of the Application, I interpret it to mean that the payment of the credit would occur only in the event that the participant is able to curtail load at the time of the coincident peak. No credits will be paid if the participant is unable to curtail or if the curtailment does not align with the coincident peak. If this interpretation is incorrect, the Public Staff recommends that NRLP clarify these terms in its rebuttal testimony or at the evidentiary hearing. The Public Staff has no objection to the proposed Schedule IR provided the payment of the credit is made clear for the record.

Q. Please discuss NRLP's proposed reconnection fees.

A. NRLP did not propose any changes to its reconnection fees ($25 during regular business hours and $60 after regular business hours) in this proceeding. NRLP stated in discovery that the utility maintained the current reconnection fees because the administrative costs to process payments and execute the reconnection are unchanged. The utility further stated that if the AMI meter failed to execute the reconnection, NRLP personnel would still need to visit the customer premise to make the reconnection. The Public Staff does not dispute NRLP's assertions around these tasks and potential difficulties of executing this work. This issue was also an issue in the Sub 46 case.[5] NRLP made a decision at that time to continue onsite, in-person reconnections and wishes to maintain that practice. Such

[5] *See* Public Staff Witness Evan Lawrence's testimony in Docket No. E-34, Sub 46.

an action may be necessary in certain situations when there are safety concerns or the inability to properly communicate with the individual meter being disconnected or reconnected. However, those concerns are also present with meters and customer accounts associated with NRLP's prepaid utility service, which allows service to be disconnected and reconnected electronically or remotely.

The Public Staff also acknowledges there are administrative costs associated with the disconnection and reconnection processes. However, I believe those costs are much less than the current $25 and $60 rates represent, mainly due to the utility's ability to avoid onsite visits by NRLP personnel and customers' ability to self-serve through the online payment option.[6] These administrative processes are similar to those offered by Duke. Duke was able to reduce the costs of reconnection resulting from the deployment of AMI meters, and the Public Staff believes NRLP could do the same. Based on this information, I recommend that NRLP amend its reconnection process to allow customers the ability to self-serve and reap the benefit of the AMI. With this self-serve process, NRLP should also be able to replace its current disconnection and reconnection fees with a single fee that reflects only the administrative costs associated with the disconnection and subsequent reconnection of service. I

[6] *See* web link https://nrlp.appstate.edu/pay-billcustomer-portal

recommend that NRLP update its reconnect fees to reflect these costs and refresh its disconnection/reconnection process consistent with my recommendations when it files its rebuttal testimony in this proceeding.

Q. Does NRLP propose to increase its residential class Basic Facilities Charge?

A. Yes. NRLP proposes to increase the residential basic facilities charge (BFC) from $12.58 to $14.50. The proposed BFC represents 40% of the $36 per month customer-related unit cost-to-serve calculated in the COSS. The Public Staff does not object to the proposed increase because the amount is well below the customer-related cost of service.

IV. Revenue Apportionment and the Phase-In of the Rate Increase

Q. Please explain how NRLP apportioned the proposed revenue requirement.

A. NRLP Exhibit REH-14 illustrates the return on rate base (ROR) associated with each customer class. Witness Halley's testimony states that NRLP relied on the Public Staff's revenue apportionment principles to spread the impact of proposed revenue changes among customer classes. Those principles include:

1. Employing a ±10% "band of reasonableness" relative to the overall jurisdictional rate of return, such that to the extent

possible, the class rates of return after the rate changes stay within this band of reasonableness following revenue assignment;

2. Limiting the revenue increase to no more than two percentage points greater than the overall jurisdictional revenue increase;
3. Moving all classes toward parity with the system; and,
4. Minimizing subsidization of customer classes by other customer classes.

Each principle is an important consideration when assigning revenue requirement to the classes.

Q. What is NRLP's approach for apportioning its proposed base revenue increase?

A. NRLP set the target ROR for each customer class equal to the overall system ROR. This approach complies with each above-listed principle but one. Strictly applying this approach to the proposed revenue increase results in a significant increase for the Commercial-Demand and "Lighting" customer classes (40.63% and 38.95%, respectively, versus the overall increase of 24.87%), well outside of the bounds for limiting the increase to no more than two percentage points above the overall increase.

Q. How has NRLP mitigated the impact of its proposed revenue increase?

A. Yes. NRLP has proposed to phase in its increase over a two-year period by reassigning some of the proposed first year base rate revenue increase from the Commercial-Demand class to the Residential and ASU customer classes. NRLP did not propose a similar strategy for the Lighting customer class. This strategy results in higher increases in the first year, followed by decreases in the second year, for the Residential and ASU classes. The Commercial-Demand class receives a lesser revenue increase the first year, followed by an additional increase thereafter, equal to the combined revenue decreases to the Residential and ASU classes.

Q. What is the Public Staff's opinion of this approach?

A. While the approach works in some respects, phasing in the increase is not acceptable as proposed. The Public Staff prefers an approach that balances the effects of each rate principle to the greatest extent possible. However, it is impossible to abide by each of the rate principles given the extent of the revenue increase that is supported by the Public Staff's audit and review in this case.

Q. Please explain which revenue apportionment principle the Public Staff believes should take precedent.

A. The Public Staff's proposed revenue apportionment assigns the Public Staff's recommended revenue increase in a manner that focuses on achieving compliance with the band of reasonableness first, followed by tempering the level of increase experienced by a particular customer class. This process also minimizes cross-subsidization.

Q. What is the Public Staff's position regarding assignment of the Public Staff's proposed base revenue increase?

A. McLawhorn Exhibit 1 illustrates the Public Staff's analysis of its proposed class revenue apportionment. Taking the revenue requirement recommended by Public Staff witnesses Johnson and Morgan, I proceeded to calculate RORs and percent increases for each class, and I do so in one year rather than NRLP's proposed two-year phase in.

Q. Please discuss the results of your revenue apportionment analysis.

A. My calculations of RORs and percentage increases could not adhere to the Public Staff's apportionment principles for any of the classes. I was able to move all classes except the ASU class toward parity (moving from negative to positive RORs), but I was not able to keep the percentage increases within two percentage points above the overall increase for the Commercial-General, Commercial-Demand, and the Lighting classes, nor could I satisfactorily address cross-subsidization. Any attempt to resolve these principles results in the same rate shock for some classes that NRLP was trying to avoid with its proposed phase in. As a result of this exercise, I am recommending that the Commission focus on mitigating rate shock first.

My calculations as illustrated in McLawhorn Exhibit 1 represent a best attempt at balancing the objectives of each of the four principles. More importantly, my apportionment avoids a phasing in of the increase over two years and tempers the potential for rate shock for the Commercial-Demand and Lighting classes by employing a more consistent percent increase for each class.

I believe this approach reasonably balances the principles of revenue apportionment for the following reasons: (1) the COSS in this proceeding relied upon NRLP-specific AMI data, which provides a more detailed and accurate understanding of NRLP customer usage and demand and (2) phasing in a revenue increase of this magnitude and reapportioning the increase to customer classes who are already paying rates that are closer to costs,[7] is not good policy as it exacerbates the cross-subsidization issue.

Customer energy usage and demand form the basis for cost causation. However, in order to honor the cost causation principle of rate design, revenue apportionment must overcome this initial hurdle of a significant overall revenue increase. If the Utility's revenue increase is justified, then customer classes are responsible for paying the costs to serve them. In addition, setting rates that require some customer classes to pay the costs of mitigating rate shock of other customer classes is usually inappropriate. This is because the principle of limiting an increase to no more than two percentage points above the overall increase effectively does the same thing. The extent of the increase in this case prevents the Public Staff from achieving a balance of the principles. At some point, certain principles must take precedent.

I recognize that some level of cross-subsidization is unavoidable in this case, and the way that I have applied the principles of revenue apportionment acknowledges this reality. I also recognize the need for gradualism in any significant rate increase. While NRLP's

[7] Under current rates, the Public Staff determined that the Residential customer class was underpaying their costs to serve as evidenced by a negative ROR (-0.43%). However, this was the least negative RORs of the other customer classes with negative RORs. The ASU customer class had a positive ROR (3.15%) under current rates.

proposal provides a gradual approach to the overall increase, it uses the Residential and ASU customer classes to accomplish the gradualism. I do not find this methodology acceptable for the proposed phase-in of the total revenue increase.

Q. **Is there any action that NRLP could take to mitigate the effect of its proposed revenue increase that the Public Staff could support?**

A Yes. The Public Staff could support a phase in of the total revenue increase over two years under three conditions. First, the Utility must avoid exacerbating cross-subsidization by asking customer classes, who are already paying rates closer to their cost to serve, to pay an additional amount simply to mitigate rate shock for another customer class, who should be paying a larger proportionate share of the revenue increase. This condition means that NRLP must be willing to forgo a portion of its otherwise justified revenue increase for one year. Secondly, NRLP should not earn or accrue any additional financial incentive (interest on deferred revenues or other financial compensation) in the interim. Finally, NRLP's proposed revenue apportionment (as provided for in NRLP Exhibit REH-15) should be recalculated to reflect the Public Staff's revenue apportionment principles by moving all customer classes into the band of reasonableness by the end of the phase-in period (end of year two). Elimination (or minimization) of cross-subsidization and moving all customer classes ROR toward parity should occur as a result of moving all customer classes into the band of reasonableness.

Q. What is the Public Staff's assessment of NRLP's quality of service for its customers?

A. Overall, I conclude that the quality of service provided by NRLP to its customers is good.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JAMES S. MCLAWHORN

I graduated with honors from North Carolina State University with a Bachelor of Science Degree in Industrial Engineering in May of 1984. I received the Master of Science Degree in Management with a finance concentration from North Carolina State University in December of 1991. While an undergraduate, I was selected for membership in both Tau Beta Pi and Alpha Pi Mu engineering honor societies.

I began my employment with the Electric Division of the Public Staff in November of 1988. I became Director of the Electric Division in October of 2006, and, with the merger of the Electric and Natural Gas Divisions, I assumed my present position as Director of the Energy Division in August of 2020. It is my responsibility to supervise the review of, and make policy recommendations to Public Staff senior management on, all electric and natural gas utility matters that come before the Commission.

I have testified previously before the Commission in numerous proceedings.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54 In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service DOCKET NO. E-34, Sub 55 In the Matter of Petition of Appalachian State University d/b/a New River Light and Power Company for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	)	**TESTIMONY OF JAMES S. MCLAWHORN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION IN SUPPORT OF SETTLEMENT**

July 6, 2023

Q. Please state your name, business address, and present position.

A. My name is James S. Mclawhorn. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Energy Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. Are you the same James S. Mclawhorn who has moved to adopt the direct testimony of Jack Floyd on behalf of the Public Staff filed in this proceeding on June 6, 2023?

A. Yes.

Q. Are your qualifications and duties the same as stated in the direct testimony you filed along with your motion to adopt the testimony of Jack Floyd?

A. Yes.

Q. What is the purpose of your settlement testimony in this proceeding?

A. The purpose of my settlement testimony is to support the Agreement and Stipulation of Settlement filed on July 6, 2023 (Stipulation), entered into between Appalachian State University d/b/a New River Light & Power Company (NRLP or Company) and the Public Staff (Stipulating Parties), as they relate to the following topics: (1) cost of capital; (2) revenue requirement; (3) accounting adjustments; (4) other adjustments; (5) other recommendations; and (6) other areas of agreement between the stipulating parties.

Q. Please briefly describe the "other areas of agreement between the stipulating parties" portion of the Stipulation.

A. The Stipulation addresses specific areas of agreement between the Stipulating Parties that have been discussed in the pre-filed testimony of the parties and, in some cases, by further clarifying discussions between the Stipulating Parties. The Stipulation sets forth the following additional areas of agreement between the Stipulating Parties:

1. The Stipulating Parties agree that the Company should closely monitor the credits accumulated, consumption patterns, revenues, and costs related to proposed Schedule NBR and file an annual report in conjunction with each Purchased Power Adjustment Clause (PPAC) proceeding.

2. The Stipulating Parties agree that proposed Schedule NBR should be amended to include the following statement: "Any renewable energy credits (RECs) associated with electricity delivered to the grid by the Customer under Schedule NBR shall be retained by the Customer."

3. The Stipulating Parties agree that it is appropriate to review the proposed design of proposed Schedule NBR, re-evaluate the energy resetting process and the Supplement Standby Supplemental Charge (SSC) in five years, and adjust the energy credit as appropriate with every PPAC filing.

4. The Stipulating Parties agree that the energy credit for proposed Schedule PPR should be based on total system avoided costs rather than just residential class avoided costs. The Stipulating Parties further agree that this calculation can be provided with the compliance filing after the Commission's final order, and then updated with each PPAC filing.

5. The Stipulating Parties agree that proposed Schedule PPR should be amended to include the following statement: "Any renewable energy credits (RECs) associated with electricity delivered to the grid by the Customer under Schedule PPR shall be retained by the Customer."

6. The Stipulating Parties agree that the design of proposed Schedule PPR should be reviewed during the Commission's biennial avoided cost proceedings.

7. The Stipulating Parties agree that for proposed Schedule IR, no credits will be paid if the participant is unable to curtail or if the curtailment does not align with the coincident peak.

8. The Stipulating Parties agree that in order to reflect the advantage of remote disconnects and reconnects made possible by the AMI metering technology, the current reconnection fees during working hours and otherwise should be replaced with one single reconnection fee of $11.50.

9. The Stipulating Parties agree that the revised rate design shown in Halley Rebuttal Exhibit No. 1, filed on June 23, 2023, which eliminates the proposed two-year phase in, is appropriate for allocation of the rate increase by customer class in this proceeding.

10. The Stipulating Parties agree that, except as denoted above, all other proposed changes to the rate schedules included in the Company's original Application are appropriate and should be approved.

11. The Stipulating Parties agree that the Commission's final order and notices to the public about the rate increase should include the decrease to the PPA factor.

Q. Are there unresolved items between the Stipulating Parties?

A. No.

Q. What ratepayer benefits does the Partial Stipulation provide?

A. From the perspective of the Public Staff, the most important benefits provided by the Partial Stipulation are as follows:

a. An aggregate reduction in the Company's proposed revenue increase in this proceeding resulting from the adjustments agreed to by the Stipulating Parties;

b. Clarifications to rate schedules proposed by the Company, a reduction of the reconnection fee under certain circumstances, and rate schedules that contain rates which are just and reasonable; and

c. The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts on the settled issues and associated increased accumulation of rate case expense recovery from rate payers.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. FELLING: Mr. McLawhorn is now available for cross examination.

COMMISSIONER KEMERAIT: Cross examination from Appalachian Voices?

MR. JIMINEZ: Thank you.

CROSS EXAMINATION BY MR. JIMINEZ:

Q. Mr. McLawhorn, just to start with, I'm gonna say "you testified." I'm referring to Mr. Floyd's testimony that you adopted. Is that okay?

A. That's fine.

Q. Okay. So you testified that Schedule NBR, and I'm quoting, makes a reasonable effort towards compliance with H-589 on page 14, lines 5 to 6?

A. (Witness peruses document.)

Yes.

Q. NRLP doesn't have to comply with H-589, does it?

MR. FELLING: I would object to that question, just to the extent that it calls for a legal conclusion, and to the extent that he's able to answer it under his own personal knowledge, I think that would be appropriate.

MR. JIMINEZ: I would just say it's no more legal conclusion than his own testimony, which

I'm asking about.

You know, the Public Staff should not be allowed to, or anyone, offer legal opinion in expert testimony and then insulate that opinion from cross examination.

COMMISSIONER KEMERAIT: So the objection is overruled.

Mr. McLawhorn, recognizing that you are not an attorney, answer the question to the best of your ability.

THE WITNESS: I think -- let me say why I think the -- our testimony is worded the way it is. We looked at 589 and we looked at what it said about net metering, and the revisions to current net metering tariffs, and we looked at what New River had proposed in this case. And we felt that it -- what New River had proposed was in alignment with what 589 said. I will leave it to the legal experts to determine whether they were required to comply with 589 or not.

Q. Thank you. So you testified that you reviewed Schedule IR -- this is on page 18, line 15 -- the interruptible rate?

A. Yes.

Q. And you found that the $14.26-per-kilowatt credit is based on the contract demand charge associated with the purchase power agreement plus an adjustment for system losses -- it's on page 19, 12 to 14 -- correct?

A. Yes. We reviewed the calculations that the Company used to support the $14.26 and found that they were supported.

Q. So you would agree, then, that NRLP's costs that can be avoided vary over time?

A. Some costs vary over time, yes.

Q. And so if a resource contributes to meeting NRLP's needs at a higher cost time, it would avoid higher costs?

A. It's possible that it could. I think it's important to remember, though, that we work in an average cost and average rate environment, and that's the way rates are designed, to recover average costs over a broad period of time. Certainly, with the end -- any period of time, not all costs are exactly the same, but that's not the way New River's rates are designed to work.

Q. The rates, but under its costs under the contracts vary over time?

A. For -- yes. For instance, their contract with CPP, their wholesale power supplier, as fuel costs vary by month, the bills that New River receives from CPP for the cost of that power can go up or down.

Q. You gave me a perfect segue to my next question, thank you. My next line.

So you note on page 9, lines 18 to 19 of your direct testimony that purchase power costs represent approximately 71 percent; is that right?

A. That's correct.

Q. And then on page 10, lines 3 to 8, NRLP has experienced volatility in its purchase power costs?

A. They certainly did in 2022.

Q. And in that same passage you note that this volatility drove New River to update its purchase power adjustment rider?

A. They came in midyear and asked the Commission for a midyear update to their purchase power cost. I will point out that the volatility that New River experienced during that time was not unlike what other utilities in North Carolina and around the country experienced during that time.

Q. And that was due, in large part, to the steep natural gas price increase, right?

A. That was certainly a major component of it, yes.
Q. And that resulted in under collections?
A. Yes, from the rate that had been set from unforeseen cost increases from purchase power rate in New River's case that had been set in advance.
Q. Okay. I think you answered.
And that ultimately had to be recovered from customers?
A. Yes. Unless the costs were found to be improved, they had to be recovered from customers.
Q. Is it your understanding that New River gets much of its power from the Kings Mountain Energy Centre, which is a combined-cycle plant?
A. That is where the majority of their power comes from, although they did -- they did receive a certain portion of their power from a renewable energy provider during that year. But the majority was from CPP, which is in Kings Mountain, yes.
Q. We're having a telepathic connection this morning.
You would agree that solar wind and hydro do not have fuel price volatility?
A. They do not burn fuel; so no, they don't --

they don't have the fuel volatility that natural gas or coal or even nuclear plants would have.

MR. JIMINEZ: I have an exhibit I'd like to introduce.

(Pause.)

COMMISSIONER KEMERAIT: Let's go ahead and get it marked. We will have this marked as Appalachian Voices Cross Examination McLawhorn Direct Exhibit Number 1.

(Appalachian Voices Cross Examination McLawhorn Direct Exhibit Number 1 was marked for identification.)

MR. JIMINEZ: Thank you.

Q. So, Mr. McLawhorn, have you had a minute to review that exhibit?

A. I have looked over it; I haven't read every word.

Q. Certainly. Do you recognize it?

COMMISSIONER KEMERAIT: Can you speak a little bit more in the microphone? We're having trouble hearing.

MR. JIMINEZ: Sorry about that.

Q. Do you recognize it?

A. Yes. This is the initial filing that New

River made back in November of 2022 for their annual purchase power adjustment.

Q. Could you please read the highlighted portion on page 2 into the record?

A. In the context of these RER calculations, it should be noted that this past year's cost of energy from Carolina Power Partners, CPP, was much higher than was projected at the time of the proposal and approval of the RER offering to NRLP customers. Although the initial calculations estimated an incremental additional cost of renewable energy of approximately $0.02 per kilowatt hour over the cost of energy purchased from CPP, the actual difference was approximately $0.02 per kilowatt hour savings.

Q. Thank you. And could you please review Exhibit D to that document, the 2022 true-up?

A. (Witness peruses document.)

Q. Do you see, in the third line, the avoided CPP energy costs are something a little over $1 million?

A. Yes.

Q. So is it fair to say that renewable energy purchased through rider RER functioned as a hedge against the fuel price spike that we just discussed?

A. It certainly did in 2022, yes.

Q. Wouldn't customer-sided solar do the same, at least with respect to the avoided energy costs?

A. It would have in 2022 when the natural gas costs were extremely volatile, yes.

Q. Which would decrease some amount of NRLP's purchase power?

A. It would have in 2022. When the RER rider price was set, it was -- we had reviewed the purchase power cost of New River leading up to that, and I believe the calculations in which, at that time, it was estimated that the renewable energy would have been more expensive than the CPP costs were based on sound data.

We all know what happened in 2022 was very unusual and a large -- in large part due to global events that impacted the cost of natural gas. So I certainly hope we don't see that again, but then there is no guarantee.

Q. Thank you. You reviewed -- I'm moving on from that exhibit, by the way.

You reviewed the calculations behind the SSC originally $6.17 per kilowatt now $5.92 per kilowatt? That's on line 14 -- page 14, line 12 to 13 of your

testimony.
A. Yes, we reviewed those. I did.
Q. And you concluded that the value of SSC is based on allocation of the transmission and distribution-related costs associated with the delivery of energy from the PPA that are not avoided. That's just following that section.
A. Yes.
Q. And you testify that the calculation of the SSC is mainly driven by the influence of the coincident peaks, page 15 line 12?
A. Yes.
Q. Were you present for -- when Ms. Barnes [sic] testimony this morning?
A. I was.
Q. So valuing customer-sided solar at an average flat volumetric rate does not take into account the cost avoided by solar's contribution to monthly coincident peak, does it?
A. Well, I listened to witness Barnes' testimony, and I didn't follow all of it, but I followed, I think, a good bit of it.
And I guess what I would say is that much of witness Barnes' testimony is probably technically

correct, but it's very difficult to base a calculation for a value that only occurs at certain times or certain hours of the day or season or year when, as I said before, we're dealing with average rates and costs that are averaged over a period of time.

So, for instance, New River -- and I'll just talk about their residential rate for now, is essentially a flat rate. So every kilowatt hour is priced at the same cost, and they have averaged the cost of their system, their distribution costs, their costs that they're charged from BREMCO, their transmission costs that they're charged from Duke Energy to get the power there.

And they've taken the total cost and they've averaged that out into a flat rate. So while it is probably true that a kilowatt hour of energy that's produced from a solar PV system may have a different value, depending on when it's produced. It doesn't change the fact that, if the customer, you know, uses that to offset some of its purchases from New River, it is avoiding paying for a portion of the distribution and transmission costs with every kilowatt hour that it offsets. I mean, it's the costs that it's offsetting are not varying, in terms of the rate, itself.

Q. In terms of the customer's rate?

A. Yes. So New River doesn't collect recovery of that cost, which means some other customer has to pick that up.

Q. Wouldn't that also be true of the compensation under Schedule IR?

A. I believe Schedule IR is based on the capacity price from Carolina Power Partners, which is priced on a dollar-per-kW basis.

So they literally -- New River won't be making that payment to Carolina Power Partners if customers are able to help them avoid, you know, the demand at that particular time. So that would be spread to all customers through their rates. That is a cost that is a -- that does vary for New River in terms of their month-to-month bill.

Q. Just to be clear, if solar contributes to meeting that coincident peak need, it would also avoid that cost, wouldn't it?

A. If it is -- if it is generating at the time of the coincident peak, it would offset at least a portion of that cost. I would point out that -- and, of course, the peaks are set monthly, but New River is a winter-peaking utility. So there -- that -- from that standpoint, they look very much like a gas LDC, if you looked at their load profile.

So there is not a lot of solar production in the winter, in the early morning. I'm not saying there's zero, but there's not a lot.

And if the peak is -- I think one of the commissioners asked yesterday, if the peak was at 4 a.m. -- which may or may not be, but it could easily be at 6 a.m. in the winter -- there's not much sunshine at that point in time, so you're not getting very much production out of the system.

So if we had -- and that's where a lot of New River's costs come from, even though they're billed to customers throughout the entire year. So if we had rates that varied with time or with season and we could match those up, there would be a stronger argument, perhaps, to varying the value of the solar and using that to potentially offset a portion of the SSC, but New River does not have rates that are set like that, at least at this point in time, retail rates.

Q. So -- okay. So it sounds like you're -- I'm trying -- I wasn't expecting to do this, but I'm trying to understand something.

It sounds like you're implying that the value of solar has to be limited by the customers' retail rate; is that right?

A. The value of solar is what it is, but the -- whether we can recognize it or not in the way that customers are compensated is somewhat limited by the way the rates are billed. The Commission, several years ago with the Duke Energy and Progress Energy, net metering riders required customers -- well, in order -- I guess they didn't require customers to be on a time-of-use rate, but they set certain parameters for how customers would be compensated as to whether they were on a time-of-use rate or not, because they recognized that time-of-use rates could somewhat account for the varying time value of the production.

But New River, at this point in time, does not have Time of Use rates. They don't have real-time rates. So there is no way to do what Mr. Barnes was advocating and there not be cross subsidization but flowing from other customers.

Q. Okay. I think I understood.

COMMISSIONER KEMERAIT: Let me interrupt. We're getting close, we're reaching the time for our morning break. How much longer would your cross examination be?

MR. JIMINEZ: I have another -- I'd say a couple of exhibits. Maybe 15 minutes.

COMMISSIONER KEMERAIT: Okay. So let's go ahead and take our morning break now then, and then we'll continue with your cross examination. So we'll be back at 10 minutes; 11:45.

(At this time, a recess was taken from 11:35 a.m. to 11:46 a.m.)

COMMISSIONER KEMERAIT: Let's go back on the record. And before we get started again, I'd ask for all of the parties who have reserved cross examination time, that before your cross examination, to please review the estimated time. I will provide all of the parties some leeway with their cross examination, but do the best that you can to keep it within the time period that you have estimated.

So let's go ahead and continue with the cross examination.

MR. JIMINEZ: Thank you.

Q. Mr. McLawhorn, your testimony indicates you consider resetting credits as one way to reduce cross-subsidization from nonparticipants to participants, correct? And that's on page 14, line 19 to 15, line 1?

A. Yes. That's the -- that's the purpose of the reset, is to offset cross-subsidization.

Q. Isn't it possible that there could being a cross-subsidy in the other direction, from participants to nonparticipants?

A. I can't envision one; I mean, if you want to give me a scenario.

Q. Such as through a combination of a very low credit rate for solar and a high fix charge? One or the other or both?

A. Not sure I understand your question.

Q. Well, let me ask this. If that were possible, the Public Staff would oppose it, would it not?

A. I'm not sure what -- I don't understand your -- I'm not sure what we would be opposing. I don't follow your question.

Q. Is there no -- so say that the fixed charge for solar customers was $100 from -- NRLP is recovering all of its fixed charges and more, and that's just what the customer is charged for having solar.

Wouldn't that solar customer be subsidizing nonparticipating non-solar customers?

A. If a solar customer were recovering $100 in fixed charges, is that what you're asking me, and then they would be subsidizing other customers?

Q. If NRLP was charging a solar customer $100 fixed fee, then more than covered NRLP's fixed charges to serve that solar customer?

A. Well, if it more than covered NRLP's fixed charges, then yes, that would -- that would constitute a cross-subsidy. But I will point out, as we talked about before, we deal with average costs, and there is no way to eliminate all cross subsidies; we're trying to minimize it.

I mean, you're always gonna have some customers that cost more to serve than other customers, and we're charging them one rate. And so when you do that, there's no way to 100 percent eliminate cross-subsidy, but we're trying to not -- we're trying to not allow certain customers to completely avoid recovery of the fixed charges that they're responsible for at the expense of other customers.

Q. Okay. But the Public Staff would want to, as you said, minimize a cross-subsidy from solar customers to non-solar customers as well, would it not?

A. Sure, yes.

Q. If there is that cross-subsidy --

A. If it exists, yes.

Q. If there is a cross-subsidy from solar customers to non-solar customers, then resetting the credits every year would deepen that cross-subsidy, wouldn't it?

A. I think there are two types of cross-subsidies. There are cross-subsidies, in terms of fixed costs, like wires and portions of the distribution network, and the demand charges that New River has to pay BREMCO and Duke Energy Carolinas for the ability to deliver power to New River.

And then you have a more energy-related cross-subsidy, which is really what I see the reset being more related to, where a customer accumulates, I will call them credits, kilowatt-hour credits, when their solar system -- in this case, behind the meter, we'll say a residential customers on the rooftop -- produces more energy than the customer is consuming. And so they -- the word we usually use, they banked these credits.

And then when you go into a period of time when your -- the customers' demand or usage exceeds what their system can produce -- let's say, in the case of New River, that would be in the winter, when the demands are the highest for their customers, mainly, I think, due to heating, electric heating load, and then that is also a time when their costs, their energy costs, from their wholesale contract would be higher.

The customer is then going to use those -- that energy that was banked during a cheaper period of time to offset energy it is now using during a higher cost period of time.

New River is still experiencing those higher costs, and they get spread to other customers. That's -- for New River, this would be somewhat like a fuel charge for Duke Energy or Dominion. But for New River, it's their purchase power cost. And so other customers would be having to pick up those higher energy costs. So, to me, the reset and the SSC both address cross-subsidy, but for some different types of costs.

Q. Okay. But on the premise that there is a cross-subsidy from solar customers to non-solar customers?

A. Given New River's load profile for the reset and when they proposed it, I'm having a difficult time accepting your premise that, for the reset portion, that solar, or behind-the-meter customers, could be subsidizing non-solar customers.

Q. Okay. I'll move on. You note on page 6 of your direct testimony, lines 12 to 16, that given New River's SCADA investments, it is now in a position to begin looking into implementing new opportunities to assist customers with more energy efficiency measures, demand response, and time-of-use rate designs; is that right?

A. That is correct.

Q. And these measures, as you say on lines 15 to 16, could help reduce or shift overall peak demand and energy consumption?

A. Yes.

Q. The Stipulation does not mention energy efficiency, demand response, and time-of-use rate designs, does it?

A. It does not.

Q. There is no commitment, for example, that New River file EE/DSM, energy efficiency or demand side management programs, in its next rate case?

A. You're correct. The Stipulation does not say that. And -- but the Public Staff's position for New River is as it is for other companies. We expect them to explore opportunities for DSM/EE programs, and hen as they are able to identify cost-effective programs, that they bring those forward for Commission approval.

So that's an expectation we have for all utilities in North Carolina, and that hasn't changed in this case. And I believe witness Miller has stated, I believe in his rebuttal testimony, that they are -- that New River is pursuing some grant opportunities. So I would certainly encourage them to continue to pursue that and other opportunities.

Q. But you would agree the Public Staff is in no position to guarantee that it will do that?

A. No. We can't force the Company to.

MR. JIMINEZ: Okay. No further questions.

COMMISSIONER KEMERAIT: And I believe that New River had reserved potentially the opportunity for cross examination.

Do you wish to cross examine Mr. McLawhorn.

MR. DROOZ: Yes, please.

CROSS EXAMINATION BY MR. DROOZ:

Q. Mr. McLawhorn, you were asked about the volatility of purchase power costs from CPP, as those costs reflect changes in gas prices. And you were asked about renewables not having volatility.

When you look at the cost of electricity for New River, purchased electricity, including during peak demand times where firm or reliable power is needed, on average, over time, is the power from CPP going to be more or less expensive than, say, displacing that entirely with renewables?

A. Well, that -- that requires some speculation; but as I believe I said on the earlier cross, at the time that the rate was set for the renewable energy rider, we were expecting that the renewable energy -- the cost for the renewable energy power would be more expensive than the cost for CPP, and that was based on the data we had at hand.

And in a normal year, I don't know that there is anything that would have changed our mind about that, so we would stand by our position -- the Public Staff and I, personally, would stand by our position when the renewable energy rider was originally approved by the commission, what the costs that were used to back that up.

Q. And you alluded to global events in 2022 that affected that volatility.

Were you referring primarily to the invasion of Ukraine by Russia?

A. Yes. And the cost of natural gas due to U.S. exports of LNG to Europe to help meet the demand there, due to Russia cutting off their supply.

Q. Was that foreseeable?

A. Not by anyone that I'm aware of.

Q. You were asked a number of questions about flat volumetric rate versus using peak demand cost for the value of solar.

Is it your understanding that, under the NBR proposal, that solar would -- energy provided by customers to the New River grid would be valued at the retail rate that New River charges?

A. Yes.

Q. Okay. And looking at the summary provided by witness Barnes, I'm just gonna read off of page 2 of that, rather than have you dig it up.

There is a sentence that says, First, the Commission should eliminate the SSC, because my analysis, which corrects more errors than New River Light and Power's evaluation, indicates the value of residential-sided solar generation slightly exceeds the residential retail rate.

Now, regarding that, and the questions you received, does the Public Staff believe the standby charge should be eliminated?

A. No, we do not.

Q. If it were eliminated, in your opinion, would that result in non-participating customers subsidizing the solar customers?

A. Yes, it would.

Q. Thank you. That's all my questions.

COMMISSIONER KEMERAIT: Redirect?

REDIRECT EXAMINATION BY MR. FELLING:

Q. Mr. McLawhorn, in cross examination from App Voices and from the Company, you've kind of been asked about the interplay between SSCs and cross subsidization.

So can you -- I wanted to give you the opportunity to just explain how, in your opinion, an SSC helps avoid cross subsidization between participating and nonparticipating customers.

A. And let me start off my answer, I'm not sitting here saying that I think the SSC that is proposed by the Company is a perfect charge. I don't think perfection is even possible in this situation.

So it's not my testimony that $5.92 is the absolute perfect number, but it is my testimony that it is appropriate that there be a charge of this type to avoid cross-subsidization, and I have reviewed the calculation for that, and it is based on what I believe is sound data. It is reproducible and verifiable. So I just wanted to -- I wanted to be clear on that on my testimony.

But the SSC is made up of different components that -- of cost that are real costs to New River, which their customers have to pay for through rates, whether it be for the investment in New River's own distribution plant, or the charges it receives from BREMCO for wheeling power across their system, or the transmission charges that Duke Energy Carolinas charges for wheeling the power from CPP across their system.

So those -- those are very real charges. to the extent that the behind-the-meter generation is not offsetting those costs or not completely offsetting those costs, there will be a certain level of those costs that will be avoided by their generation, but will have to be picked up by other customers and -- that are not -- do not have behind-the-meter systems.

And that constitutes cross-subsidization and that's something that we know is there, and that has been an issue with net metering rates throughout their history. It's been a concern of net metering rates throughout their history.

Q. To your knowledge, are there any charges that are contained in the SSC that are also duplicated in a basic facilities charge for the Company in this case?

A. The basic facilities charge is designed to pay for a portion of the cost of not only the customers' meter and the service drop leading to the customer's home or business, but also a portion of the distribution cost. In the SSC, there is also a portion of the New River's own distribution system cost.

And I heard some questions yesterday. I believe Commissioner Clodfelter was asking that. So I went back and I checked the calculations again to make sure that I was satisfied that there was no double-dipping, in effect. And so the portions of the distribution system, based on my analysis, that are recovered through the monthly basic customer charge, are not included in that portion of the distribution costs that make up the SSC charge. So there should not be any double dipping.

Q. And I wanted to turn to some questions that you were asked about the resetting of solar credits or energy credits. And your response was, to my recollection, also related to prevention of cross-subsidization.

So I wanted to give you the opportunity to expand on that cross-subsidization, and then also give your opinion whether some form of resetting is necessary to ensure that cross-subsidization does not occur.

A. Yeah. Whenever -- and this is -- this has been the Public Staff's concern, it's been a concern of this Commission in the past in their orders. Whenever energy is produced and banked during periods of low cost, and then the customer is able to draw on that during higher demand and higher cost periods, they're still placing a demand on the utility to go out and secure that power, but they get to offset their costs for it with the lower-cost energy that they banked.

So those costs, they are very real and they're still there, but because the net metering customer is offsetting part of their usage with the banked energy, then the other customers who aren't net metering customers have to pick that up and pay for that. So that causes a cross-subsidy, and so that's why the resetting is important.

Now, in the -- in the Duke Energy net metering riders, and the Commission issued the Order, I believe it was E-100, Sub 190, we now have a monthly settle-up. So if there is any excess, it doesn't carry over from one month to the next and the customer gets -- essentially gets paid for that excess at some type of avoided cost. That is -- my understanding is that is not something that New River's system -- their metering and billing system can handle that, certainly at this point in time. I'm not saying they can't in the future. That would be an alternative to having, like, an annual reset, but that's not something that's available right now.

Q. And in your opinion, does the annual reset that's been proposed to reset the energy credits in this case, it's sufficient to address the cross-subsidy issue that you just discussed?

A. Well, and as said, it's sufficient for it. That doesn't mean it 100 percent offsets it. Because as I said, it's impossible to design perfect rates.

MR. FELLING: No further questions from the Public Staff.

COMMISSIONER KEMERAIT: Okay, thank you.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Mr. McLawhorn, I'll begin, and let me step back and just ask you a question that you haven't talked about yet about service from New River.

Have you -- I assume that the Public Staff attended the public hearing and also has done an investigation about service.

And can you describe efforts to improve service from New River and Public Staff's position about adequacy of service?

A. Well, certainly, the Public Staff has received no concerning level of complaints from customers about the service level they're receiving. I did not hear any concerns at the public hearing. I was at the public hearing, as you were.

Most of the witnesses that appeared there were talking about the net metering issue. I believe there was one witness that commented on the targeted undergrounding that New River has done in some neighborhoods. And certainly their -- the service quality indices that were provided by New River are satisfactory. So as far as I'm concerned, I believe the service they are providing is adequate.

Q. And then one of the topics about the SSC that we haven't touched on very much is about what should be based upon, and we have -- I would like to hear the Public Staff's position.

Appalachian Voices believes it should be based upon the system design capacity, and then New River has done it based inverter nameplate capacity.

Can you talk a little bit about what the Public Staff's position is about this issue that relates to the NBR and Public Staff's support of that schedule in the stipulation?

A. Well, I mean, I won't dispute Mr. Barnes' testimony. It could have been calculated on the system design capacity, and perhaps that would be a more accurate calculation. I have not had an opportunity to have discussions with other parties about that. I mean, it's a denominator, ultimately. You are dividing something into a level of costs.

And I don't know that using the nameplate capacity is a bad way to do it. As I said, it may not be the absolute best or most appropriate. But I don't think -- the Public Staff would not have a problem with exploring a more appropriate way. Although, we are satisfied with -- at this point, with the calculation.

That's one of the reasons we recommended that this be re-evaluated by the Commission at some point in the future, and I believe our testimony in the Stipulation says five years. If the Commission felt that it should be more frequent review than that, then I'm sure the Company and the Public Staff would work with that.

I think it's important to remember this is -- this is New River's first attempt at a true net metering rider. And so there are -- they're gonna learn a lot from this and what their system is capable of handling. And I think what they proposed is a reasonable attempt at implementing that at this time. Again, not testifying it's perfect, and not testifying that it can't be made better.

Q. And that kind of leads to my next question about what's been recommended in the Stipulation is a review in five years. And I think you heard witness Barnes, who testified that he objects to having NBR schedules in place and a review in five years, because he believes the customers would be over-billed during that five-year period.

And you already touched upon this, but can you state succinctly for the record about Public Staff's position in regard to overbilling if the review occurs in a five-year period?

A. Well, you know the -- we don't have retroactive ratemaking, so we don't rebill customers on anything that I know of, except perhaps fuel, and maybe a couple of other riders that we try to true up if we find that there's been an overbilling or an underbilling on an annual basis.

I would, again, say that I view this -- the charges that are included in rider NBR, I believe are reasonable and are based on sound data, but we'll go back and re-evaluate that at some point in the future, either five years or whatever time period the Commission feels is most appropriate, and we'll adjust that if and when we find there is something that is more appropriate.

Q. So I guess just to ask you very directly about this, does the Public Staff have real concerns or significant concerns about overbilling then?

A. No, not at this point in time. If we did, we wouldn't have entered into the Stipulation, if we had serious concerns about overbilling.

Q. And then about the basic facilities charge. The Public Staff did not contest New River's proposed increases to the basic facilities charge.

Can you explain why the Public Staff took that position?

A. Well, New River's analysis was essentially the minimum system approach, and they identified a cost of about $36, is what could be justified. A minimum system is what has been used by other utilities in the state and approved by the Commission, and so we didn't take issue with their use of minimum system. They did have an increase in the charge.

I believe, for Duke Energy Progress, Duke Energy Carolinas, and Dominion, I believe their basic facilities charge is $14, or right around that. So our evaluation, New River technically could justify a higher charge. The charge they proposed was in the ballpark of what other utilities in the state are charging that are regulated by this Commission. So we did not have any -- we did not have any concerns with it.

Q. And just for correction or clarification of the record, it was the modified version of the minimum system effort, correct?

A. Yes, yes.

Q. Okay. And then along those lines, New River's witness Halley states that this modified version of the minimum system method is more in line with North Carolina utility regulation than the approach that's been suggested by Appalachian Voices witnesses.

Does the Public Staff agree with that position -- or that statement or disagree with that statement? You've sort of answered it already, but I'd like to hear a direct answer to that question.

A. Yeah. I think my review of Appalachian Voices' witness was that they used -- or they preferred the minimum customer method, and they were coming up with the lower charge. Although, I believe they did go back and attempt to make some adjustments to the modified minimum system, but we're really -- now we're talking like a dollar here and a dollar there. And I don't mean to minimize costs, but we're sort of splitting hairs at this point. And we did not see any significant reason to take issue with the Company's proposal.

Q. And then, just a couple of questions about the reset -- the annual reset for the NBR schedule.

In New River's rebuttal testimony, their witness has stated that they would agree to eliminate -- to go along with Appalachian Voices's recommendation of eliminating the annual reset. And then in the Settlement Stipulation, the annual reset was included in what was agreed to between New River and the Public Staff. And you've talked quite a bit already about that annual reset.

Is the Public Staff's position that -- that it absolutely must -- that we must have this annual reset to prevent cross-subsidization? Is that something that's critical for the Stipulation that you entered into?

A. The short answer is yes. And we had -- I testified that, I believe, the proposal by New River meets the requirements or the policies that are outlined in 589 for net metering. Of course, I said it's up to the Commission and the legal experts to decide if New River has to comply with 589, in terms of net metering.

But certainly, that was the basis or one of the bases we used for evaluating NBR. And 589 requires either -- I don't have it in front of me. It's either minimization or elimination of cross-subsidy.

And so we believe that it is -- absent of some other way to account for the cost of energy from one period to the other that I described earlier -- and I won't go back into that -- we believe that the reset is essential.

Q. Okay. And then my last question is related to Appalachian Voices' witness Barnes' testimony. He, of course, believes that there should not be an annual reset. He said in -- I think his -- he says if there is an annual reset, he disagrees with it being on January 1st, and he proposes that the customer should be able to choose the reset period.

What is the Public Staff's position about having a reset period that the customers could select, rather than a standard January 1st reset period?

A. Well, I -- I'm gonna give you an answer, and I don't want to disparage customers, because they're gonna act, for the most part, in their best interest as most people do. If they were allowed to pick when the annual reset occurred, perhaps they might pick some time coming out of the winter when there was no excess bank of energy and they -- and then they -- it wouldn't help offset the cross-subsidization issue.

So in my opinion, it is appropriate to have the reset at a period of time when there's been a significant bank of energy at low cost that has built up prior to moving into a period of high cost. If the Commission, I'm sure, remembers that for Duke and

Progress, the reset was on June 1st. At that time when that was established, that was when they were summer-peaking utilities, and you had had a significant bank of energy built up over the spring, which is a lower-cost, lower-usage period of time. And then you were moving into the summer, which was a higher demand due to their air conditioning load and higher cost. And that was why it was determined that it was appropriate for them leading into the summer.

Here, with New River, you have a heavily winter-peaking utility, so I believe -- I don't know if January 1st is the absolute right, but it should be sometime leading into the winter period.

Q. Okay. Thank you.

COMMISSIONER KEMERAIT: Chair Mitchell?

EXAMINATION BY CHAIR MITCHELL:

Q. All right, Mr. McLawhorn. I won't -- just a few for you. We talked some -- you've testified today about volatility with respect to gas prices. And I've -- I understand the volatility that we've experienced in the past couple of years and reasons therefore, so we don't need to cover that ground again.

But what can you tell me about, to the extent that you know, any mechanisms in the contract with

Carolina Power Partners to reduce volatility in pricing or otherwise protect customers from volatility and gas pricing?

A. I am afraid I am not intimately familiar or prepared today to discuss the wholesale contract with Carolina Power Partners.

Q. Okay. And I'll ask Mr. Hinton the same questions to see if he has anything to share.

A. He may know more than I.

Q. Okay. Are you sure you want to admit to that? Just a joke.

A. He would tell you he does anyway.

Q. I'm sure he would.

All right. So, I mean, you know, typically -- the reason for my question is, you testified that a majority of the power supplied to New River comes from the Kings Mountain facility, which is a natural gas-fired facility. So there is not a lot of diversity there -- fuel diversity, with respect to the electricity that's being provided to customers. And so I'm just concerned about dependence on that single source of electricity and implications for customers, so.

A. We -- the Public Staff shares those concerns.

Q. Okay. What do you know about Kings Mountain's performance during Winter Storm Elliott, if anything?

A. I know some things, but I think what I know is confidential, so I don't think I'm allowed to say.

Q. Okay. That's fine.

What do you know about back standing of Kings Mountain, who back stands?

Let me ask my question this way: Does New River have a source of back-standing supply?

A. Well, I know that for Kings Mountain, if they are unable to generate, they are required to go out and secure power, so -- to back them up. So to that extent, New River is protect- -- I don't know all the details of Kings -- Kings Mountain's back-up supply guarantee, but they -- I mean, obviously, it's one plant, and they can't operate 365 days a year, even if -- even if it doesn't break, it's gonna have to come down for maintenance at some point, and there's still gonna be a demand from their customers. So they have to go out and secure that power.

Q. Okay. So make sure I understand you correctly, the back-standing obligation rests with Kings Mountain and not with New River Light and Power?

A. That's the way I understand it, yes.

Q. And do you know -- do you know anything about where Kings Mountain is? How is Kings Mountain seeking back-standing service?

A. I don't know. I assume they work with other power marketers or they have their own power marketing.

Q. Would you know --

A. But I don't know. I don't know.

Q. If and I understand, and I won't pressure you there. But I will ask you this one question, and if your answer is "I don't know," I understand.

Is Kings Mountain back-stood by Duke, DEC?

A. They would be for a period of time. I mean, if the plant trips, you know, they're not gonna immediately have somebody waiting in the wings at that instant, and so Duke would be the back-stand party. But I believe within -- usually, the NERC requirement is within 15 minutes they would have to have some other source of power.

Q. Okay.

A. And it could be that they would get Duke to cover that for a period of time, but I don't -- I'm speculating a little bit now.

Q. And I understand. I'll accept that your testimony is speculation.

And so then do I understand your testimony to be that federal law or federal regulation obligates DEC to back-stand New -- Kings Mountain -- the Kings Mountain facility?

A. I don't know that federal law requires it. I mean, it just by the laws of physics.

Q. Okay. I wanted to make sure I understood what you're saying. So you're saying the electrons are gonna flow, and they're going to come from DEC --

A. Because they are the closest source of power.

Q. Okay.

A. What the contract or the terms they have literally say on paper, I don't know.

Q. Okay. All right. Thank you, Mr. McLawhorn, I appreciate it.

COMMISSIONER KEMERAIT: Commissioner Brown-Bland?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Yes. I just want to go back for a minute on the annual reset and stipulation, and that it's to be reviewed every five years at this point.

Mr. Barnes testified that one of the concerns is kind of -- if you can separate it from the overbilling, was just that, because of that overbilling, I guess, that the subscription may be less during this five-year period because of whatever realities the customers are experiencing and perceive about this -- about, you know, what's happening and the value and benefit to them.

Is that lack of -- lower level of subscription, if it were to develop, that that is something that you see occurring within that five-year period.

Is that something that's worthy of consideration, and what's the Public Staff think about that as one of the issues?

A. You mean at the five-year review, would that be worthy of consideration then or now?

Q. Now, I'm asking, yeah, now. Should we look at that, and what's the Public Staff think about that, in terms of if -- if sooner than the five-year period, if we were seeing that they were -- was a low subscription?

A. Well, like I said it earlier, if the Commission feels that it ought to be looked at earlier than five years, then that's your call. Five years was the settled number.

And so as to your -- the other part of your question, I mean, I'm not an expert in net metering system economics. I will agree that the $5.92 is a high charge.

No, you asked about the reset, I'm sorry. The reset, sorry. We certainly know from past history with the Duke Energy Carolinas and Duke Energy Progress customers, they don't like the reset. I can't tell you how many complaints we've had from customers, but they still installed, you know, net metering systems. Now I know many people would argue we don't have enough net metering systems, but it has grown significantly over the last few years. So it has not kept customers from installing. Maybe it has, you know, limited the number of customers that are interested, but it certainly has not stopped. And it is -- the concerns are valid about what would happen without a reset and -- you know, in terms of the cross-subsidy.

Q. Right. And if the -- I guess I'm asking if we saw, before the five-year review, that the reset -- the annual reset was having an impact one way or the other, is that something that the Public Staff would think significant or think worthy of consideration now as we sit here to make that decision?

A. Well, since we've entered into a stipulation with the Company, and assuming the Commission accepts the Stipulation, it would be something that I think both parties would have to agree to, but we would be willing to engage in discussions with the Company about that.

Q. What would you think about it, just in general, outside the stipulation, though? Is it -- I'm just trying to get a -- is it -- I think Commissioner Kemerait used the phrase earlier when she was asking about the overbilling, and I'm asking about the other piece.

But is it significant, insignificant, you know? Or would you just default to it's reasonable at this point?

A. I guess it's one of those things where you would consider it at the time. I mean, it's hard to know exactly what motivates a customer to install or not install a system on their roof. Is it -- if they don't, is it solely because of the reset? Is it solely because of the SSC? Is it solely because some other costs of the system or equipment have increased?

At this point, it's hard to just single out this one thing and say, well, if net metering -- if New

River doesn't have a 200 percent increase in net metering within five years, it's all because of the reset. I don't -- I don't know how to put a weight on that -- a percentage on that, so.

Q. All right. Thank you.

COMMISSIONER KEMERAIT: Commissioner Duffley?

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So good afternoon. I had a question about the reset as well, and just some clarification of your testimony or what I heard, and to make sure what I heard is what you said.

So you stated the annual reset right now is in the beginning of January?

A. January 1st, I believe.

Q. And did I hear you say that, because this is a winter-peaking system, that it might be more appropriate to have that reset in -- at a different time period?

A. I said it possibly -- because I consider December a winter month, even though, I guess, technically winter doesn't begin until December 21st, maybe a reset would have been more appropriate on December 1st, but definitely in the winter timeframe.

Q. Okay. But not August or September?
A. No, no, no.
Q. You're thinking December --
A. Yes.
Q. -- might have been -- so just a month?
A. Heading into the winter.
Q. Heading into the winter, got it.
A. Yes.
Q. Okay. Thank you for that. And then my one other question, you discussed that the Stipulation does not require EE and DSM.

If the Commission wanted, hypothetically, to encourage EE/DSM, does the Public Staff have any suggestion of programs, or would the Public Staff think that New River should suggest those programs?
A. I think New River is the only entity that knows what their costs are and could evaluate what it would cost to implement those programs. Now, I think it's perfectly appropriate if the Commission wants to make suggestions for New River to evaluate.

I think witness Miller has said they are pursuing grants for high-efficiency heat pumps and water heaters and programmable thermostats. And I believe they're also possibly looking into some weatherization programs.

But again, we would -- we would want those programs to be cost-effective and -- two things are working against New River. One, they're very small, and so they don't have a large customer base. There's gonna be a certain level of overhead or fixed cost associated with any program, and they don't have a large customer base to spread those costs.

And number two, I think about three-quarters of their housing units are rental properties, meaning they're not owner occupied. That's not what -- they're not -- whoever is occupying does not own the facilities, sort of like multifamily.

I know the Commission is aware of the -- even some of the difficulties that the larger utilities have had with multifamily programs. Because the person who's making the investment, the landlord or the owner, is not the same person who is living there and getting the benefit out of it.

So to the -- certainly, we don't just want to write it off and say there is nothing that can be done, but I would really caution against mandating that New River go do certain programs until they've had an opportunity to investigate the costs and report those back to the Commission.

Q. Okay. Thank you for that.

COMMISSIONER KEMERAIT: So, Commissioner McKissick, before we get started, we do need to take our lunch break no later than 12:45, so if you can complete your questions by that time, you can go ahead.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. Just a follow-up on the question Commissioner Duffley was asking about DSM and EE.

To what extent did Public Staff work with New River to evaluate some options that might be plausible, given the limited size of the customer base, which is about 4,400 customers or so? You know, and given the -- you know, they're peculiar financial capacity, okay? I mean, were there options evaluated?

Because I understand your last remarks as well, and I read similar remarks, you know, in documents related to the case. This is an area that I think needs to be thoroughly investigated in scores.

I mean, how far do you go down a pathway with them, or to what extent were there discussions held?

A. In this case, I would say not extensive discussions. We have talked with them in the past, and certainly, as was pointed out, that there were, in the Stipulation in their last rate case, their Stipulation with the Public Staff, they made a commitment to evaluate programs in particular that could -- they could take advantage of their AMI metering to offer those -- the conversations that we have had with the Company have been they are still -- still evaluating.

Of course, they just got the SCADA system -- the new SCADA system implemented that they said was important to offering, not only DSM and EE programs, but some -- looking at some time-of-use rates.

And so, I guess, we're still -- the Public Staff is still waiting for the Company to come back to us and say, "This is what the results of our investigation have shown." We have not pressed them to a great extent on that at this point. But we will -- we will continue to have conversations with them, is what I would say.

Q. And is there a reason why they haven't been pressed more than what has occurred?

A. Just understanding some of the difficulties that they face, but if the Commission would like for us to be more aggressive with the Company in pursuing those, we will certainly be happy to do that.

Q. Sure. Thank you, sir.

COMMISSIONER KEMERAIT: Okay. Let's go ahead and go off the record.

(The hearing was adjourned at 12:40 p.m. and set to reconvene at 1:40 p.m. on Tuesday, July 11, 2023.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was conducted, do hereby certify that any witnesses whose testimony may appear in the foregoing hearing were duly sworn; that the foregoing proceedings were taken by me to the best of my ability and thereafter reduced to typewritten format under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 14th day of July, 2023.

JOANN BUNZE, RPR

Notary Public #200707300112